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Long-term dynamics of investment decisions in electricity markets with variable renewables development and adequacy objectives

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"If light is scarce then light is scarce; we will immerse ourselves in the darkness and there discover its own particular beauty. But the progressive Westerner is determined always to better his lot. From candle to oil lamp, oil lamp to gaslight, gaslight to electric light – his quest for a brighter light never ceases, he spares no pains to eradicate even the minutest shadow."

Jun'ichiro Tanizaki, *In praise of shadows*, 1933.

"The scientific man does not aim at an immediate result. He does not expect that his advanced ideas will be readily taken up. His work is like that of the planter – for the future."

Nikola Tesla, *The Problem of Increasing Human Energy*, 1900.

Abstract

In liberalised electricity systems, power markets are expected to ensure the long-term coordination of investments in order to guarantee security of supply, sustainability and competitiveness. In the reference energy-only market, it relies on the ability of power markets – where the hourly price is aligned with the marginal cost of the system – to provide an adequate price-signal for investors. However, in practice, questions have been raised about its ability to trigger investments in Low-Carbon Technologies (LCT) including in particular Renewable Energy Sources of Electricity (RES-E), and its ability to ensure capacity adequacy.

After a characterisation of these market failures, this dissertation tackles the two research topics within a methodological framework based on a System Dynamics model developed to simulate private investment decisions in power markets.

First, the results show that substituting out-of-market support mechanisms for RES-E by market-based investments helped by the sole implementation of a carbon price appears as a feasible solution to trigger RES-E development providing that there is a political commitment on a high carbon price.

Second, it also appears that the energy-only market with price cap is ineffective to ensure capacity adequacy in a context of mature markets with conventional thermal power plants under transition paths which involve a stable electricity demand thank to energy efficiency efforts and the exogenous development of RES-E thanks to support mechanisms in the absence of a high and fixed carbon price. Adding a capacity market or removing the price cap both bring benefits in terms of Loss Of Load Expectation (LOLE) and social welfare. Moreover, considering two various energy transition scenarios and different assumptions about the risk aversion of private investors, the capacity market is identified as the best option for regulators among the considered market designs.

Key words: Electricity markets, Investments, Renewables energy sources, Capacity adequacy, System Dynamics modelling.

Résumé

Les marchés électriques libéralisés sont supposés assurer la coordination de long-terme des investissements afin de garantir sécurité d'approvisionnement, viabilité et compétitivité. Dans le modèle de référence energy-only, la formation des prix par alignement sur le coût variable de l'équipement marginal sur les marchés horaires successifs fournit un signal prix pour les investisseurs. Cependant, en pratique, ce modèle est remis en question quant à sa capacité à déclencher des investissements dans les technologies bas-carbone et en particulier les énergies renouvelables (EnR) et quant à sa capacité à garantir la sécurité d'approvisionnement.

Cette thèse cherche d'abord à caractériser ces deux défaillances de marché puis s'intéresse à différentes solutions pour faire face à chacune d'entre elles. Pour cela, la réfléxion s'appuie sur un modèle en System Dynamics développé afin de simuler les investissements dans les marchés électriques.

Les résultats montrent que le remplacement des mécanismes de support hors marché par des investissements par le marché avec l'aide d'un prix du carbone apparait comme une solution pour déclencher le développement des EnR à condition d'un engagement politique fort en faveur d'un prix du carbone élevé.

Il apparait aussi que le marché energy-only avec des prix plafonnés ne parvient pas à assurer l'adéquation en capacité dans un contexte de marchés électriques matures avec des centrales thermiques conventionnelles faisant face à des scénarios de transition énergétique. L'ajout d'un marché de capacité ou la suppression du plafond de prix permettent une amélioration en termes de nombre d'heure de délestage et de bien-être collectif. De plus, en considérant deux scénarios de transition énergétique et plusieurs hypothèses sur l'aversion au risque des investisseurs privés, le marché de capacité apparaît comme le meilleur choix pour le régulateur parmi les architectures de marché considérées.

Mots-clés : Marchés électriques, Investissements, Energies renouvelables, Adéquation de capacité, Modélisation en System Dynamics.

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"Ce qu'on cherche, on peut le trouver; mais ce qu'on néglige nous échappe."

Sophocle, *Oedipe Roi.*

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[1] Je précise que l'outil développé pendant ma thèse a été initialement nommé *Outil pour l'Etude Dynamique des Investissements dans la Production Electrique* (OEDIPE).

nombreux stagiaires avce qui j'ai partagé des moments (des pauses !) très agréables. La liste serait trop longue ici, mais je suis sûre qu'ils se reconnaîtront ! Parmi eux, je remercie spécialement Maxime et Soumaya pour m'avoir donné de leur temps pour relire certaines parties de cette thèse.

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Marie

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Abbreviations

Acronym	Full form
ACER	Agency for the Cooperation of Energy Regulators
CARA	Constant Absolute Risk Aversion
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CFO	Chief Financial Officer
CRRA	Constant Relative Risk Aversion
CT	Oil-fired Combustion Turbine
DSO	Distribution System Operator
EDF	Electricité de France
ENTSO-E	European Network of Transmission System Operators for Electricity
EU-ETS	EU Emissions Trading System
EUSE	Expected Unserved Energy
FIP	Feed-In Premium
FIT	Feed-In Tariff
IEA	International Energy Agency
IRR	Internal Rate of Return
LCOE	Levelised Cost Of Electricity
LCT	Low-Carbon Technologies
LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
NPV	Net Present Value
NSE	Non-Supplied Energy
OECD	Organization for Economic Co-operation and Development

O&M	Operations and Maintenance
OTC	Over The Counter
PI	Profitability Index
PV	Solar Photovoltaics
RES-E	Renewable Energy Sources of Electricity
RSD	Relative Standard Deviation
SD	System Dynamics
SIDES	Simulator of Investment Decisions in the Electricity Sector
TSO	Transmission System Operator
UK	United Kingdom
USA	United States of America
VaR	Value at Risk
VOLL	Value Of Loss Load
WACC	Weighted Average Cost of Capital
WT	Wind Turbine

To Basem, for his unwavering love and support...
To my parents, for having consistently believed in me from the beginning...

General introduction

> "ELECTRE *n.s. Amber; which, having the quality when warmed by friction of attracting bodies, gave to one species of attraction the name of* `electricity`*, and to the bodies that so attract the epithet* `electrick`*."*
>
> Samuel Johnson, *A Dictionary of the English Language*, 1755.

The liberalisation of the power sector has completely changed the paradigm of generation units. The previous vertically-integrated utility service monopoly was based on the "cost-of-service" regulation model of pricing in which the electricity price was defined to compensate the average production cost. It has been replaced by a de-verticalised organisation with competition between generators upstream and suppliers downstream leading to a "market-based pricing model" (Borenstein and Bushnell, 2015). In the new model of competitive markets, generating assets get paid for the electricity sold on wholesale markets but without any long-term arrangements to guarantee the sufficient recovery of fixed costs. Indeed, this change in the remuneration paradigm of generation units – from average production cost to short-term marginal cost – had been a major motivation of the liberalisation. More specifically, in the early 1990's, many countries in Europe and the United States experienced a structural overcapacity inherited from the monopolies. In such a situation, generation assets were not used at their optimal operating durations, leading to a paradoxical situation with increasing generation costs and decreasing short-term marginal costs due to the overcapacity. Hence, the liberalisation of the sector was seen as a great opportunity to reduce the electricity bill of large consumers through their direct participation to wholesale markets. In that sense, in most countries, the liberalisation of the power sector was primarily motivated by the introduction of competition in short-term operations and less attention was paid to long-term efficiency (Joskow, 1997).

The reform of the electricity sector was focused on the four activities of generation, transmission, distribution and retailing which consists in the commercial relationship with final consumers (Jamasb and Pollitt, 2005, Borenstein and Bushnell, 2015). Transmission grids as well as local distribution grids, considered as natural monopolies, were therefore separated from generation and supply activities seen as potentially competitive activities. In principle, the four aforementioned activities are to be performed by separate companies. In practice, the unbundling of transmission and distribution grids is not always clear-cut on the one hand, and generation and supply tend to be partly vertically integrated on the other hand.

Besides, the market design and the industrial structure of liberalised power systems can be diverse depending on the institutional legacy particular to each country. More importantly, this architecture is still under construction and is expected to evolve in response to the current and future trends on both generation and demand sides. Future power systems can involve smaller decentralised units under policies promoting the development of variable renewable plants (windpower, photovoltaics) with new opportunities to adapt the electric demand to real-time signals. Historically, the interaction between generation, transmission, distribution and supply was mainly organised in a "one-way direction" from the generation to the transmission, distribution and finally to the supply. However, this structure is largely likely to evolve due to the increasing role of distributed energy sources which could completely change the consumer paradox and the role of self-generation in the future.

This general organisation of liberalised power systems based on the unbundling of the different activities is supposed to create incentives for efficiency and innovation motivated by competition. In this context of different activities of the value chain being fulfilled by independent entities, electricity markets should ensure the twofold short-term and long-term coordination function.

The twofold coordination function of electricity markets

In liberalised power systems, coordination mechanisms are needed to ensure the sound functioning of the four activities (generation, transmission, distribution and supply) operated by separate unbundled companies with several competing producers. In this

context, energy markets have emerged as the central element of the coordination of generators upstream and suppliers downstream. At the same time, the market design of liberalised power systems also encompasses sub-markets to offer specific products (balancing, ancillary services) to the Transmission System Operator (TSO) in order to guarantee system reliability in the real time, while providing locational price signals for generators. Thus, electricity markets should ensure the coordination of operating actions in the short-term and the long-term coordination of investments in generation and, to a lesser extent, transmission. Firstly, in the short-term, energy markets guarantee efficient operations of existing plants and demand response. Secondly, price signals indicate scarcity (or surplus) of capacity for the different technologies and thus, guide investors' long-term investment (respectively retirement) decisions. In theory, short-term and long-term market coordination signals are consistent under the assumption of pure competition, perfect information and no risk aversion. However, as developed further in this dissertation, different market failures can be identified.

Short-term coordination of operating actions

In the short-term, the use of different plants spanning several technologies should be organised according to both technical and economic considerations. To this end, short-term electricity markets aim at coordinating the different participants in order to serve the demand at least cost while respecting the operational constraints of electricity systems.

The **day-ahead electricity market** is considered as the first element[2] of the operational coordination of power systems through the selection of the plants according to the merit-order of the different operators' bids on the hourly[3] markets. Then, balancing and ancillary services markets allow for real-time adjustments to the evolutions of the electricity system. The short-term electricity prices can be structured on nodal or

[2]Generally, intra-day electricity markets can be considered as a continuation of the day-ahead electricity market.

[3]The day-ahead market can also be defined on half-hour basis.

zonal basis to reflect local scarcities of transmission capacity[4]. More specifically, short-term power markets can be analysed through the identification of four building blocks (Hogan, 1998, Stoft, 2002, Saguan et al., 2009): (i) forward energy market which generally corresponds to both day-ahead energy markets and intraday markets, (ii) forward transport market, (iii) forward reserve requirements and finally (iv) the real-time block which mainly refers to the balancing and ancillary services markets. Each of these blocks has several organisation options leading to a variety of power markets' architectures.

Long-term coordination function of energy markets

On longer horizons, economic signals coming from energy markets are supposed to trigger investment decisions in new generation units eventually including demand response. In particular, wholesale electricity markets are supposed to guide new investments in different technologies by "creating rents to support fixed investment costs in a relatively small number of hours" (Joskow, 2006b). The recovery of fixed investment and operating costs is ensured by the so-called "infra-marginal rent" which refers to the difference between the variable costs of the considered generator and the hourly price aligned on the bid of the marginal generator. The anticipation of these future rents is supposed to trigger investment decisions in the different technologies including peaking units despite the fact that they will only run during the few hours[5] of extreme peak demand, varying from one year to another. In doing so, the long-term coordination of power systems by electricity markets aims at guaranteeing the capacity adequacy which is defined as "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times" (NERC, 2016).

Investments in generating capacities are generally characterised by a capital-intensive cost structure[6], an irreversible one-step process and a long payback period, which are

[4]Generally, electricity prices are nodal in the US and zonal in Europe. More precisely, in almost all European countries, day-ahead electricity prices are defined for the whole country; except in Italy where there are six market areas, in Norway where there are five market areas and in Sweden where there are four market areas. In most other European countries, the zonal day-ahead price is defined for each hour of the following day and it respects some technical constraints of power units that are translated in the bids of electricity producers. Then, the networks constraints are taken into account into real-time balancing markets. On the contrary, electricity markets in the US directly define nodal electricity prices that reflect technical constraints of power generation units and networks' constraints.

[5]These extreme peak demand period during which peaking units generate electricity are known as "scarcity period".

[6]At least one technology cannot be considered as capital-intensive: Combined Cycle Gas Turbine (CCGT).

all to be decided with a high level of long-term uncertainties (Olsina et al., 2006). In liberalised power systems, there is no long term guarantee of cost recovery as it was generally the case before the liberalisation reforms by construction of the retail prices, as pointed out above. Consequently, investments are confronted to a more risky environment, thus a threat of under-capacity on the long-term. However, it should be noted that only two decades after the liberalisation of the European electricity sector, the experience on the long-term investment signals remains insufficient when compared to the long lifetime of generating technologies (Green, 2006).

This dissertation proposes to focus on the long-term coordination function of liberalised electricity markets and more specifically on investments in electricity generation. Indeed, long-term issues of electricity markets seem to have received less attention than short-term operations since the liberalisation reforms (Joskow, 1997) and continue to raise a number of legitimate questions (Cramton and Stoft, 2006, Aïd, 2010, Finon, 2013).

Market failures in the long-term coordination function under policy objectives: Present and future challenges

While energy markets are supposed to ensure the long-term coordination function of investments, different market failures can be identified with regard to the ability of market signals to trigger investments. More precisely, incentives to invest in capital-intensive equipments are particularly restricted compared to other technologies that involve lower fixed costs. Among these capital-intensive equipments facing market failures, two specific contexts can be identified for (i) peaking units which are essential for capacity adequacy, and (ii) Low-Carbon Technologies (LCT) and Renewable Energy Sources of Electricity (RES-E) which participate in the decarbonisation of the electricity sector.

Market failure to invest in capital-intensive equipments

The restructuring of electricity markets was based on the idea implied by Joskow and Schmalensee (1983) that if generators were not able to bear investments risks, the previous vertical integration could be replaced by bilateral contracts between generators and retailers (or large consumers) through multilateral markets for spot trading and through

financial markets for hedging arrangements. This would suppose the completeness of markets including financial hedging products with long maturity (IEA and NEA, 2007). However, Chao et al. (2008) show that restructuring based on unbundling and short-term market trading is not sufficient to hedge against all generation risks and thus they support that a balanced mixture of vertical integration (by long-term arrangements) and liberalised markets is superior to the two extreme situations, namely an energy-only market without long-term contracts on the one hand, and a vertically integrated utility monopoly on the other hand. Besides, in most countries, there is no financial market which could offer long-term hedging products to generators. Consequently, generators are incentivised to invest in equipments with low capital costs as for example Combined Cycle Gas Turbine (CCGT) rather than capital-intensive technologies[7].

Specific market failure impeding investments in peaking units for guaranteeing capacity adequacy

According to the peak-load pricing theory (Boiteux, 1949, Joskow, 1976), electricity markets should theoretically ensure that short-term scarcity situations during peak-load periods are reflected in wholesale prices, providing long-term signals for investments in different technologies. The implementation of scarcity pricing constitutes a recurrent issue of designing electricity markets. In particular, scarcity rents during few hours of extreme peaks or other exceptional situations should provide investment signals in favour of peaking units needed for long-term reliability. Thus, peaking units can be considered as particularly capital-intensive plants given that their investment cost is to be recovered on very few hours.

In this context, growing evidence suggests that current electricity markets fail to guarantee supply reliability according to reliability criteria set by policy makers. Firstly, the implementation of price caps resulting from the political unacceptability of very high power prices constitutes a regulatory imperfection that leads to chronic revenues shortage for plant operators, known as the *missing money* in the academic literature. Secondly, risk aversion related to investing on the basis on very uncertain revenues during scarcity events can explain that investment in peaking units is lower than the level

[7] Roques et al. (2008) and Roques (2011) highlight this effect by modelling optimal portfolio choices. CCGT presents two main advantages for private investors: (i) a low initial up-front investment cost, but also (ii) a correlation between hourly market prices and variable cost, for a significant number of hours when CCGT is the marginal technology.

which ensures long-term reliability under risk-neutrality assumptions. Thirdly, administrative procedures as the preventively use of reserves can further disrupt investments in peaking units (De Vries, 2007, Joskow, 2008). In addition, the market failure to invest in peaking units is further amplified by the development of variable RES-E with low marginal costs (Cramton et al., 2013). Indeed, during peak periods, electricity generated by RES-E at low variable cost displaces the merit-order curve to the detriment of peaking units whereas there is an additional risk of wind scarcity during these peak periods.

Specific market failure impeding investments in LCT and RES-E

Price signal emanating from the sole power market can fail to fully incentivise investments in LCT and RES-E for several reasons identified in the academic literature (Jaffe et al., 2005, Hepburn, 2006, Lehmann and Gawel, 2013).

Firstly, non-mature[8] LCT and RES-E face specific investment difficulties caused by their very high cost compared to other technologies and increased by the difficulty in benefiting from learning effects (Del Río and Unruh, 2007, Negro et al., 2012). Secondly, in addition to investment risks worsened by a cost structure with a high share of investment cost and low or zero variable cost, LCT and RES-E also face important political and regulatory risks exacerbated by the low credibility of the carbon price signal[9] stemming from an emissions trading system (Grubb et al., 2008). Besides, additional risks exist for variable non-dispatchable RES-E because of their uncertain generation profile and its correlation with peak-load periods. Consequently, even in areas where a carbon price is implemented, investments in several LCT and RES-E are supported by specific mechanisms[10] designed to guarantee long-term revenues and to reduce long-term risks through transfer arrangements.

[8]Indeed, LCT and RES-E include several technologies with different levels of economic maturity: wind power, photovoltaic and biomass are almost mature technologies whereas marine energies are not mature yet.

[9]Market players' perceptions of regulatory and policy uncertainties can also have a significant effect on the carbon price (Koch et al., 2014).

[10]For example, feed-in tariffs, feed-in premiums or green certificates are different specific mechanisms to promote RES-E technologies.

Present and future challenges for the long-term coordination function

The market failures related to the long-term coordination function of investments and the expected solutions to address them are bound to play a major role in the evolution of power systems. In particular, the development of distributed generation and innovations in digital devices could open up strong opportunities in the role of demand side and its potential participation to the balance of consumption and generation. Besides, electricity consumption is expected to be stable or decreasing in most developed countries[11]. Combined with out-of market RES-E entries, it suggests that the value of conventional existing plants is likely to decrease, potentially causing early retirements and challenges for capacity adequacy and security of supply in the future.

In the following, this dissertation addresses two key long-term coordination issues: (i) investments in LCT and RES-E characterised by high fixed costs and low or zero variable costs, hence the complexity of investment decisions in electricity markets with marginal pricing, and (ii) capacity adequacy to guarantee supply reliability in any given situation in the context of mature electricity systems disrupted by entries of RES-E capacities with variable generation.

Research questions and methodology

Focusing on the generation function, this dissertation tackles long-term coordination issues in a liberalised electricity system by addressing two key research questions.

In a market design without specific support schemes, what carbon price can trigger market-based investments in variable renewables?

On the one hand, the current functioning of electricity markets raises legitimate questions as to its ability to trigger investments in Low-Carbon Technologies (LCT) including in particular Renewable Energy Sources of Electricity (RES-E) which are characterised by high upfront investment costs and low or zero variable costs. However, climate change considerations and the willingness to achieve energy independence can explain that these

[11] This is suggested by at least two recent reports: IRENA (2014) and NREL (2015).

particular technologies should be encouraged from a social point of view. In this context, many LCT and RES-E are currently supported by out-of-market mechanisms in many countries. Usually, these specific supports to LCTs including RES-E consist in a guarantee of remuneration with a low level of risks for a long time period (commonly more than a decade).

On the other hand, these mechanisms, designed to boost the development of LCTs including RES-E, lead to the co-existence of two investment regimes: (i) a market based investment process for conventional technologies and (ii) an out-of-market investment process for many LCT and RES-E. While the long-term functioning of electricity markets still raises a number of questions, the massive out-of-market entry of LCTs including RES-E increases both the volume-risk and the price-risk for conventional generating technologies under the market-based investment paradigm and thus, further disrupts the long-term coordination of investments. This can be seen as a clear paradox from the economic perspective of liberalised electricity markets (Finon, 2013) which has to be tackled in order to ensure capacity adequacy of future power systems.

In this context, it seems reasonable to reconsider the support mechanisms to LCTs including in particular RES-E in order to estimate if it could be possible to shift to a unique investment regime that would apply to all types of generating technologies. This is precisely the first research question addressed in this dissertation. The objective is to assess whether the implementation of a carbon price (which is translated into an increase of the variable cost of each generating technology according to its emission factor) would trigger market-based investments in LCTs including RES-E.

How can a capacity mechanism enhance the capacity adequacy in a mature power system facing energy transition policies?

Another critical aspect of liberalised electricity systems is their ability to guarantee a socially-acceptable capacity adequacy. Indeed, it is still unclear whether liberalised electricity markets can provide a sufficient level of electricity supply (Hogan, 2005, Joskow, 2008, Finon and Pignon, 2008, Keppler, 2014) as the former electric monopoly was intended to do before the reforms of most electricity systems. Moreover, this issue is even more crucial in the context of the current massive entry of intermittent RES-E as wind power and solar power which are characterised by an undispatchable electricity

generation. To address this long-term issue of capacity adequacy, different evolutions of the market architecture are suggested and analysed (Pérez-Arriaga, 2001, De Vries, 2007). In particular, the different capacity mechanisms vary in their setting of capacity remuneration, technologies concerned and time horizon.

In this context, the question of capacity adequacy is raised in power systems facing energy transition policies which is translated into a massive entry of variable RES-E and a stable electricity demand thanks to efforts in energy efficiency. The objective is to quantify how different market designs, including the implementation of a capacity-wide capacity mechanism, can enhance the capacity adequacy and the resulting social welfare of power systems.

Besides, private investors in liberalised electricity markets are now facing significant uncertainties on the long-term evolution of supply and demand sides of power systems. Thus, considering risk aversion in investment decisions can tend to less installed capacity, thus a further disruption compared to the socially-optimal level of capacity. As a result, the generation mix can be more or less far from the socially-acceptable level of security of supply depending on the market architecture and the inherent level of uncertainties that is seen by investors. For this reason, this second research question is addressed in the context of risk-averse private investors in order to quantify how risk aversion affects the generation mix under the different studied market designs.

Methodology

In this dissertation, these research questions are tackled from the point of view of private investors in liberalised electricity markets with imperfect information on the future evolution of electricity demand. To do so, the adopted approach consists in a new System Dynamics model which has been developed for this purpose and which is called Simulator of Investment Decisions in the Electricity Sector (SIDES). The choice of this methodological approach is justified by the importance given to the feature of private investors with (i) economic-based investment criterion with a certain level of risk aversion, (ii) myopic imperfect foresight, (iii) delay between investment decisions and commissioning of new power plants and (iv) the possibility to decommission existing power plants before the end of their lifetime if they are not economically profitable. Besides, the System Dynamics approach is designed to focus on temporal evolution (rather than long-term

equilibria) and thus allows to observe and quantify how past decisions or exogenous decisions can influence the future evolution of electricity systems. This latter aspect is particularly relevant in the context of the current liberalised markets with inherited capacities and significant development of RES-E pushed by energy and climate policies.

Organisation of the dissertation

The **first chapter** analyses the long-term coordination function of electricity markets and the ongoing related challenges. In particular, this chapter addresses the issues of investments in Low-Carbon Technologies (LCT) and Renewable Energy Sources of Electricity (RES-E) and capacity adequacy, and summarises the state of the art of the literature on these topics.

The **second chapter** focuses on the modelling of investment decisions in electricity markets with discussions on investment criteria, uncertainties, risk aversion and the different approaches to take these features into account in a long-term model of electricity systems. Then, the chapter provides a detailed description of the System Dynamics model[12] which is introduced as an analytical framework to tackle the two research questions.

The **third chapter** focuses on the market-based development of LCTs including in particular RES-E with a stable carbon price known in advance, rather than specific support schemes as currently in most countries. On-shore wind power is chosen as a representative renewable technology because of its relatively mature development. Supposing the shift to a single market-based investment paradigm for RES-E as well as conventional plants, this chapter intends to assess how investments in wind power can be triggered by the market and to quantify the magnitude of the carbon price which would be needed. This chapter is based on a published article[13].

The **fourth chapter** analyses the specific issue of capacity adequacy in the context of energy transition under different market designs: the energy-only with price cap considered as the benchmark and two reformed designs, namely the energy-only market with scarcity pricing and the addition of a capacity mechanism to the energy market

[12]The Simulator of Investment Decisions in the Electricity Sector (SIDES) was entirely developed from scratch for this PhD dissertation.

[13]Petitet, M., Finon, D., and Janssen, T., 2016. Carbon price instead of support schemes: Wind power investments by the electricity market. *The Energy Journal*, 37(4):109-140.

with price cap. The comparison is carried for different levels of risk aversion and for two different paths of energy transition including a path with exogenous closures of some coal and nuclear power plants. This chapter is based on a working paper[14] and on a conference paper[15] which involves risk averse investor behaviours.

[14]Petitet, M., Finon, D., and Janssen, T., 2016. Ensuring capacity adequacy during energy transition in mature power markets: A social efficiency comparison of scarcity pricing and capacity mechanism. CEEM Working Paper n°20.

[15]Petitet, M., 2016. Effects of risk aversion on investment decisions in electricity generation: What consequences for market design? In Proceedings of the 13th International Conference on the European Energy Market.

Chapter I

Long-term investment incentives in liberalised electricity markets

* * *

The current debate on market design for the power sector cannot be dissociated from the issue of investments in electricity generation. The electricity sector has some specificities that make it particularly complex but fully interesting to study from an economic and technical point of view. In several countries, the power sector has seen a complex transformation from a central planner model to a totally liberalised organisation with private investors taking their decisions in a risky environment. Thus, this new paradigm completely changes conditions of decision-making process and raises new challenges for investments in electricity generation.

This chapter starts with an overview of power systems' characteristics explaining the specificities of power markets in section I.1, before addressing the particular role of these markets for the long-term coordination of investments in section I.2. The chapter then discusses two key long-term issues of the generation function. Section I.3 addresses the difficulties associated with investments in capital-intensive equipments in the context of environmental and climate policies. Then, section I.4 discusses long-term capacity issues and some design options to enhance the long-term efficiency of liberalised power systems.

Contents of chapter I

I.1 Identifying and analysing the specificities of power systems

Electricity is not a common commodity particularly because physical equilibria can differ from economic equilibria of the market. This effect results from the limited storage capacities which cause the rigidity and price-inelasticity of the real-time supply on one side, and a specific commercial relationship with end-users through ex-post payments which partly explains the price-inelasticity of short-term demand on the other side. In practice, economic supply-demand equilibria come from hourly (or semi-hourly) markets whereas physical equilibria are managed independently by the system operator. Contrary to most mono-product industries with one dominating industrial process, the power sector is characterised by a mix of different technologies in relation to the specificities of the demand and supply functions.

This section starts with a characterisation of electricity demand in subsection I.1.1 and of the supply-side in subsection I.1.2, before discussing how demand-response could realign physical and economic equilibriums in subsection I.1.3. Finally, subsection I.1.4 analyses how the different electricity products can be identified based on the specificities of power systems.

I.1.1 Specificities of electricity demand

Price inelasticity of electricity demand

Electricity use is more similar to a service or an intermediary good than similar to a final product. In that sense, when the electricity bill is to be paid after the consumption period and when it represents a small share of their revenues, small or medium-size consumers are quite insensitive to electricity prices. However, there is a distinction between short-term and long-term price elasticities of electricity consumption. In long periods, people can adapt their source of energy toward the one appearing to be the least expensive. Meanwhile, it is impossible for consumers to change the processes and appliances in short periods but it is possible on some occasions to modulate their electricity consumption (see I.1.3). In the economic literature, several studies aim at estimating the price elasticity of electricity. Lijesen (2007) proposes a synthesis of these

studies and points out the lack of real-time elasticity estimations. According to these estimations which were conducted in various contexts, the long-term price elasticity of electricity demand varies from -0.1 to -3.4 while the short-term price elasticity generally remains between -0.8 and 0. Although estimations are very different from a study to another, it confirms the intuition that the short-term price elasticity of electricity demand is much more limited than the long-term one. Therefore, the very low short-term price elasticity of electricity consumption can be identified as a driver for the high wholesale price spikes during extreme peak periods. It may also facilitate the exercise of market power, from the part of generators, to increase their net surplus during these hours (Kirschen, 2003) eventually to recover the fixed costs of peaking plants.

However, large consumers should be distinguished from small consumers in particular in the price elasticity of their electricity consumption. Usually connected to the transmission network, large consumers are rather directly exposed to the wholesale market prices, and consequently they are more able to adapt their energy consumption to the large variations of hourly prices.

Variability of electricity demand

Electricity consumption in a given area significantly varies from year to year, from month to month and from hour to hour. These variations are generally not explained by the variations of hourly electricity prices. Indeed, electricity consumption is highly sensitive to at least three drivers: (i) the weather conditions[1] which can drive some electrical uses as lighting, cooling and heating devices, (ii) the economic activity which can influence the volume of electricity consumption and its shape, and (iii) the day of the week, the season and the hour of the day which can drive the level of consumption depending on the activities of consumers at that hour and thus it can influence the shape of electricity consumption.

[1]For example, in France, the electricity consumption increases by approximately 2,400 MW when the temperature decreases by one degree Celsius during the winter period (RTE, 2015). France is responsible for roughly half of the European consumption-temperature gradient of Europe in winter. This high variability of the French electricity consumption is partially explained by the high use of electric heating: between 2005 and 2009, more than 60% of new residential housing was equipped with electrical heating. In 2014, roughly 30% of new residential housing is still equipped with electric heating, among which two thirds correspond to heat pumps.

Thus, analysing a given power system needs to well represent the fluctuations of electricity consumption. In particular, hourly data and a representative number of weather scenarios can be necessary.

I.1.2 Specificities of electricity supply-side

In order to serve the demand, the supply side of electricity markets is provided by electricity generation units – either large power plants or smaller decentralised ones – for the most part and by actions on the electricity demand to a lesser extent.

Electrical energy can be generated by several technologies from the conventional thermal power plants to the decentralised Renewable Energy Sources of Electricity (RES-E). Each thermal generating technology is characterised by at least two dimensions: (i) its costs among which social costs in terms of environmental impacts, and (ii) its specific operational constraints (start-up time, minimum running time, minimum downtime and gradients). To put it simple, peaking units have high variable costs, low fixed costs and fast start-up and shut-down times. Base-load units have low variable costs, high fixed costs and generally long start-up and shut-down times. Mid-load units have characteristics in between. As long as available storage facilities are limited, each of these generating technology is used when it is the most appropriate in terms of economic relevance and technical feasibility. On their part, RES-E generate electricity when their primary sources (for example wind, solar, waves) are available depending on weather conditions. Besides, this latter type of technologies is generally of smaller power capacity size and they can be decentralised and connected to the low-voltage network.

Operation of power plants under technical characteristics

A first distinction should be made between dispatchable and non-dispatchable power plants. A practical definition of the dispatchable character of power units is given by Joskow (2011): dispatchable units "can be turned on and off based primarily on their economic attractiveness at every point in time both to supply electricity and to supply network reliability services". On the contrary, non-dispatchable or in other words variable generation units can only partially be controlled. Their available production is directly related to weather conditions such as wind speed, clouds or water flow. In

that sense, variable generation units can be disconnected from the grid if technologically feasible in specific situations[2] but their generation level cannot be fixed at will.

Dispatchable technologies are mainly conventional thermal technologies and nuclear power. Each of those technologies has its proper technical constraints[3]: start-up time, ramp rate, minimum running time, downtime and minimum stopping time. The different dispatchable technologies also vary in their probability of forced outages. Forced outages are defined as the technical impossibility to generate electricity due to unplanned technology failures. Usually, technical maintenance works are planned by the plant's operator in periods during which the power unit is not expected to generate electricity so that energy revenues are maximised and the functioning of the system is not disrupted.

Cost structure of generating units: towards defining the theoretical optimal technology mix

Each generating technology is characterised by its cost structure and in particular by the ratio between fixed costs and variable costs. The different costs of generating technologies and the terminology used in this dissertation are precised in appendix A. Table I.1 summarises assumptions on technologies' characteristics for four typical conventional technologies and one renewable technology: nuclear power plants (Nuclear), combined cycle gas turbines (CCGT), coal-fired power plants (Coal), oil-fired combustion turbines (CT) and wind turbines (WT).

When storage capacities are limited and given that there are several generating technologies with different cost structures (and different operational characteristics), it would not be economically optimal to generate all the needed electricity by a single technology. In fact, serving the electricity demand at low cost can be achieved only through a combination of several generating technologies. Conceptually ,the optimal generation mix can be defined based on (i) the cost structures of the different technologies and (ii) the

[2]It could be relevant to disconnect variable generation units in at least two specific situations: (i) to manage local congestions and (ii) to balance supply and demand in case base-load units have operational constraints which prevent them from decreasing their generation.

[3]See Aïd (2014) for detailed examples.

	Nuclear	CCGT	Coal	CT	WT
(a) Costs					
Investment cost (k€/MW)	2,900 - 5,000	800	1,400	500 - 590	1,600
O&M cost (k€/MW.year)	75 -100	18 - 20	30 - 50	5 - 10	20
Annual fixed cost (k€/MW.year)	309 - 504	89 - 91	147 - 167	52 - 60	170
Variable fuel cost (€/MWh)	10	64	37,5	157	0
(b) Technical constraints					
Nominal power capacity (MW)	900 - 1,400	480	750	175	45
Construction time (years)	6	2	4	2	2
Lifetime (years)	50 - 60	30	40	25	25
Forced outage rate (%)	5	5	10	8	–
Start-up time (minutes)		30 - 60		5	–
Stopping time (hours)	24	3 - 8	4 - 8	2 - 6	–
Ramp rate (% per minute)	1 - 5	5 - 10		40	–
(c) Environmental impacts					
Emissions rate (ton of CO_2/MWh)	0	0.35	0.8	0.8	0

Sources: IEA and NEA (2010), DGEC (2008) and D'Haeseleer (2013) for details on nuclear.

TABLE I.1: Characterisation of the different generation technologies.

monotonous load duration curve[4] which is a common simplified approach to analyse the electricity demand. In practice, the generation mix should also allow for the generation of a sufficient volume of electricity in relation to electricity consumption in each period while complying with operational constraints.

The *screening curves* method is a classical and common approach to define the optimal generation mix for a given load duration curve under simplifications on the power units' functioning (Stoft, 2002, Green, 2006). This method is related to the marginal cost pricing introduced by Boiteux (1949). As noted in Stoft (2002), this theory was developed in the context of regulated power systems but it is still relevant to get insights on competitive markets.

The *screening curves* approach proposes a graphical illustration of the problem of defining an optimal generation mix. To do so, this approach needs assumptions on the cost of generating technologies and on the load duration curve to be served. The load duration

[4]The monotonous load duration curve corresponds to hourly electricity consumption sorted in descending order within a year. This simplified representation does not allow for a good understanding of the electricity demand within a year because it does not considers time relation between hours. However, such a representation is sufficient to: (i) get an estimation of the operating periods for an existing generation mix or (ii) define "from scratch" an optimal generation mix for a given load duration curve.

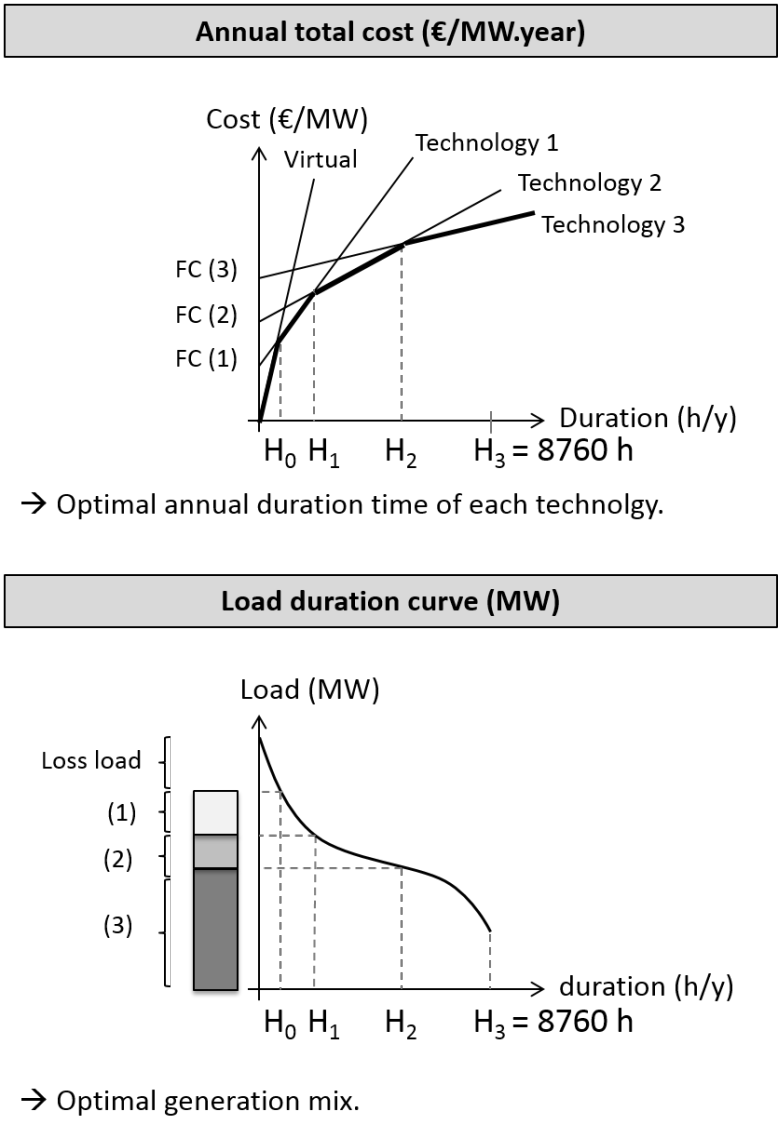


FIGURE I.1: Defining the optimal generation mix by screening curves.

curve is considered as time-invariant and can either correspond to the real electricity demand or to the net demand addressed to the conventional units when subtracting the electricity generated by RES-E, hydro-power or storage capacities.

Each technology considered to define the optimal mix is characterised by an annualised fixed cost (FC in €/MW.year) and a variable generation cost (VC in €/MWh).

The first step consists in plotting a straight line indicating the total annual cost of a MW of installed capacity as a function of the number of functioning hours. For each technology, the intercept of its "screening curve" corresponds to the annualised fixed cost and the slope is the variable generation cost. This graph makes it easy and

graphically intuitive to identify the optimal functioning duration of each technology in order to minimise the total cost of serving the demand. It allows for the definition of the duration times during which each technology is marginal. Then, the optimal duration times of the different technologies are used together with the load duration curve to define the optimal capacity of each technology as illustrated in figure I.1.

If there is an explicit capacity target to be respected, it is simple to add a "virtual" technology so that its functioning time matches the criterion of security of supply. Virtually, this additional technology is characterised by a zero annualised fixed cost and by a variable cost set at the Value Of Loss Load (VOLL).

Environmental impacts and effects on the optimal generation mix

Electricity generating technologies also differ on their environmental impacts and in particular on their emission ratio of Greenhouse Gas (GHG). Generally, most of environmental impacts remain externalities which are not translated into cost for producers. However, climate and environmental policies can involve the cost internalisation of a number of externalities and in particular CO_2 emissions.

In a nutshell, conventional thermal power plants (coal-fired and oil-fired power plants and to a lesser extend gas plants) cause significant environmental impacts[5] while nuclear power and Low-Carbon Technologies (LCT) including RES-E are more environmentally friendly regarding GHG emissions[6].

Considering the social costs of technologies could alter the optimal generation mix if internalising by taxation (or equivalent mechanism) and thus it could change the comparison between the different technologies (Roth and Ambs, 2004). More specifically, internalising environmental impacts can have two major consequences. Firstly, when variable renewables represent a significant share of the generation mix, subtracting variable generation from the electricity demand can significantly reshape the load duration curve, thus a change in the optimal capacity of conventional technologies. Secondly, adding social costs tends to increase variable generation costs of conventional thermal technologies but to different degrees. As a consequence of these two major effects, the

[5]For more details, Gagnon et al. (2002) synthesise studies on the environmental impacts of generating technologies and in particular greenhouse gas emissions (CO_2, SO_2 and NO_X) and land use.

[6]In normal operation, nuclear power is almost free of CO_2 emissions. However, nuclear incidents can cause very significant environmental damages.

optimal generation mix is likely to change in terms of total thermal capacity and share of the different technologies.

Non-storability and inelasticity of supply during extreme peak events: toward price spikes

In deregulated power markets, when available generating capacity exceeds electricity demand, the hourly price is set to the marginal generation cost of the last plant that clears the market (Boiteux, 1949) as illustrated by demand $D1$ in figure I.2. But during extreme peak events, the electricity demand can be higher than available capacity resulting in infeasible market clearing as illustrated by demand $D2$ in figure I.2. This situation is explained by the limited storage capacities and by the inelasticity of supply when no more capacity are available in real-time. In this situation, the hourly price is theoretical set by the consumers' willingness to pay to use electricity during such extreme peak events (Wilson, 2000) which can significantly exceed the higher marginal production cost.

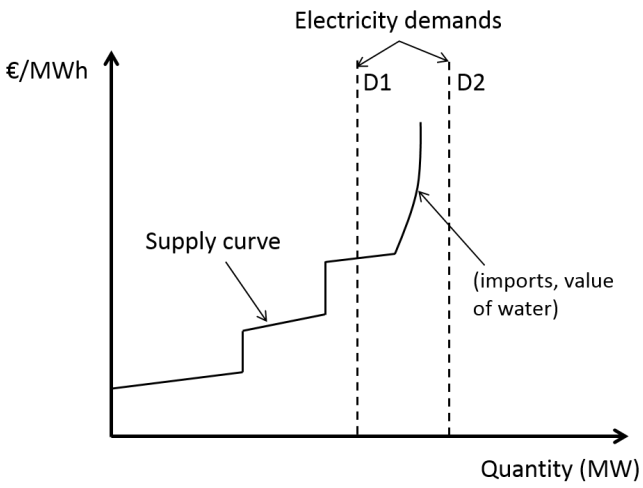


FIGURE I.2: Impossible balance between supply and demand during extreme peak events.

I.1.3 Demand-response, a way to realign physical equilibrium and market equilibrium

Depending on the country, the electricity demand can reach very high values during few peaking hours within a year (see subsection I.1.1). These events are challenging to

manage because the demand can be so high that installed capacities are not sufficient to generate enough electricity and it is not possible to adapt the capacity to the demand in the real-time. Similarly, in the former utility model, it may also be too costly to install conventional peaking plants to ensure reserve margin and to rapidly follow the varying net demand in the short-term. A fortiori, in liberalised markets, private investors would bear very high risks (price and volume risks) to invest in peaking units. In such context, an alternative to building more peaking units lies in a reduction of the effective electricity demand by the so-called load shedding or load shifting. This concept of managing the electricity demand to help the functioning of electricity systems is generally referred to as Demand-Side Management (DSM) and Demand-Response (DR)[7]. Usually, DR depends on short-term signals and on the long-term action, it benefits to the electricity system in terms of less installed capacity. In practice, DR can be achieved through time-seasonal tariffs or time-of-use tariffs on the one hand, or through specific DR contracts between the Transmission System Operator (TSO) and industrial consumers or DR contracts between aggregators and small consumers on the other hand. Besides, industrial consumers who directly participate to wholesale markets can also reduce their consumption based on real-time price signals, even in the absence of specific contracts.

The highest potential relies on industrial DR which corresponds to changes in organisation in order to adapt the production schedule to real-time wholesale electricity prices. In practice, industrial DR generally requires small fixed costs (costs to adapt the functioning of the industry) but high variable costs corresponding to (i) the opportunity cost of shifting or dropping out the production or (ii) the extra-cost of using an alternative source of energy. Another potential of DR lies in the rationalisation of electricity consumption of households or tertiary sector. To do so, electronic devices are necessary to intelligently control electricity consumption. Because each site (households or small businesses) has a relatively small consumption, high fixed costs is required to deploy the so-called "smart meters" and related devices. Once the technology is installed, there is roughly no variable cost in the use of households and small businesses DR.

[7]DSM encompasses larger concepts than the ones included in DR. According to the International Electrotechnical Commission glossary, DSM is defined as a "process that is intended to influence the quantity or patterns of use of electric energy consumed by end-use customers" and DR is defined as an "action resulting from management of the electricity demand in response to supply conditions". For more details, see `www.electropedia.org`.

In a context with high variation of the net electricity load exacerbated by the introduction of variable electricity generation by RES-E, developing demand-side participation seems particularly relevant (Strbac, 2008, Cappers et al., 2010, Torriti et al., 2010).

I.1.4 Defining electricity products based on the specificities of power systems

Organisation and design of power markets are driven by the specificities of the supply and demand sides. This also implies that electricity products can be multidimensional based on the characteristics and physical laws of power systems, making electricity products very different from traditional storable commodities. In particular, electricity cannot be considered as a common commodity because physical equilibria can differ from economic equilibria of power markets. Indeed, on the one hand, physical electrical flows go from one source to a sink according to the path of least resistance and are managed independently by the system operator. On the other hand, commercial equilibria are defined based on price comparison through hourly (or semi-hourly) power markets. This difference between economic and physical equilibria explains that congestion management mechanisms are implemented to coordinate system operations between the different market areas raising potential conflict of interest issues (Glachant and Pignon, 2005). Besides, in some cases, unscheduled flows can appear on alternative current lines between neighbouring bidding zones (phenomenon known as *loop-flows*) raising issues for the allocation of these external costs between the different affected zones.

From the the consumer's point of view, there is no difference between the electrical energy provided by a nuclear plant and the one produced by a wind turbine. Electricity seems to be a homogeneous product like any other commodity. However, this first impression of perfect substitutability between the different sources of electricity is clearly insufficient to understand the electricity product and the functioning of power markets (Hirth et al., 2016). Indeed, the physical laws of electricity have driven the market design of power systems toward the exchange of a diversity of electricity products.

As pointed out above, one key characteristic is that electricity cannot be easily stored[8]. As a consequence, the organisation of the power system must ensure that the quantity

[8]Pumped hydro power is the only commercial technology that can store electric energy. Other storage devices (batteries, flywheels, super-capacitors, etc.) are not widely used in large interconnected systems in 2016. See IEA-ETSAP and IRENA (2012) for technical information on electricity storage.

of electricity produced corresponds exactly to the quantity requested by consumers at any time. The impossibility to store large amount of electricity is the cornerstone of the organisation of power systems. In that sense, the definition of each electricity product relies on at least five dimensions which explain its heterogeneity:

- The **nature** of the product "electricity" can not be confined to a single definition. Depending on the case, it can refer either to a quantity of energy (measured in MWh) or an available power / a capacity (measured in MW). Some electricity products correspond to the effective activation and generation of a quantity of energy while other electricity products refer to the guarantee of an available power capacity during a given period.

- The **specified quantity** is probably the most obvious dimension of the product (expressed in MWh or MW depending on the nature). However, transporting electricity implies a loss due to the Joule effect and therefore, this has to be taken into account in the coordination of power systems.

- The **specified time** of delivery constitutes a relevant dimension of the product. The constraints induced by the limited possibility of storage – and thus the limitation of arbitrage over time – explain that the electricity product is heterogeneous across time. Therefore hourly prices can significantly vary from one hour to another.

- The **specified place** of generators and consumers is a dimension that has to be respected thanks to the use of transmission and distribution networks. In this regard, transmission constraints due to the limited capacity of power lines can appear and thus, it explains that electricity prices for a given hour can differ between two interconnected areas (or between two nodes in nodal pricing systems).

- The **lead-time** between the time of the contract and the time of delivery can be considered as a last and less intuitive dimension which is caused by flexibility constraints (Hirth et al., 2016).

In addition, other characteristics may also define the electricity product for end-consumers among which reliability, quality or environmental impacts (Woo et al., 2014).

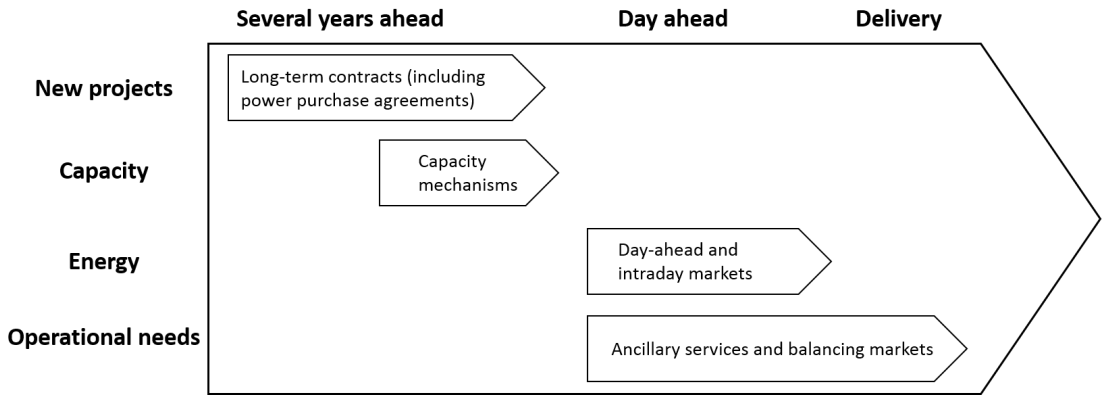


FIGURE I.3: Timeline of coordination by markets until delevery time.

From electricity products toward power markets

The different electricity markets are the roots of power markets' organisation. Indeed, the design of a liberalised power system is based on a combination of markets. Among them, retail markets[9] are designed to organise the relationship between electricity suppliers and final consumers. Wholesale markets organise the relationship between generators and suppliers plus eventually large industrial consumers. As other products, electricity can be sold from generators to suppliers either through Over The Counter (OTC) transactions or through organised markets.

Focusing on wholesale electricity markets illustrated in figure I.3, their design primarily aims at ensuring economic dispatch and the electricity transmission balancing for the purpose of the security of the system (Wilson, 2002). This can be achieved by economic dispatch through merit-order of price bids on the day-ahead forward market on the one hand, and by balancing services and ancillary services markets on the other hand. More specifically, wholesale markets have two main coordination functions: (i) a short-term coordination of scheduling (Saguan et al., 2009) to ensure efficiency in the use of existing capacities to serve the demand and (ii) a long-term coordination of investments (Green, 2006, Finon and Pignon, 2008). In theory, these two functions are totally consistent and the long-term mix invested in by generators under the short-term pricing corresponds to the optimal mix if there is pure and perfect competition, perfect information and no risk aversion (Stoft, 2002, Green, 2006).

[9]Retail prices can be either regulated by an independent administration or proposed by suppliers. Since the liberalisation of the electricity sector in Europe, consumers are free to choose their supplier with regulated or unregulated tariffs.

I.2 Analysing the long-term coordination functions of electricity markets

The power sector is specific on several points among which the particularly high interdependence of generation, transmission (including transport and distribution) and reserves. In practice, the whole power system that includes these three main components should be able to serve the electricity demand at all times. In this context, in addition to the system operation function provided by the Transmission System Operator (TSO), coordination of investments in electricity markets is one of the key elements of the well functioning of power systems. For the purpose of this thesis, the discussion focuses on investments in electricity production (and Demand-Response (DR)[10]) triggered by supply-demand balance and the corresponding price-signal.

I.2.1 Long-term coordination of investments by electricity markets

In liberalised power systems, electricity markets are supposed to ensure long-term coordination of investments in generation, transport and distribution assets in order that the future installed capacities will be able to serve the future electricity demand (Stoft, 2002, Finon and Roques, 2013). Regarding generating plants (and DR programs), the day-ahead market theoretically sends price-signal for long-term coordination. More specifically, investment decisions of generators based on price signals in a liberalised context with pure and perfect competition should in theory lead to the long-term equilibrium that would result from a social planner with marginal cost pricing. This can be achieved only if generators (and the social planner) perfectly anticipate the future.

In the literature, the energy-only market is the reference market design providing perfect long-term coordination of investments (Caramanis et al., 1982). Under this reference design, the hourly market price is equal to the marginal short-term cost of generating electricity when all demand is served; and equal to the Value Of Loss Load (VOLL) when demand exceeds available capacity to ensure scarcity rents for producers. More specifically, for each hour, the electricity price is set by the short-term marginal generation

[10] In practice, new generating units or DR programs can be needed for several reasons among which demand/supply equilibrium but also network congestions. However, network issues are out of the scope of this thesis.

cost of the last unit that clears the market according to the economic merit-order principle. This price-signal is supposed to trigger investments in the different technologies in order to reach the optimal generation mix. Then, when the generation mix is optimal, infra-marginal rents and scarcity rents are supposed to exactly correspond to the fixed costs for each technology. In the case of peaking plants, marginal profit during peak periods is supposed to equal marginal capital cost. The socially optimal generation mix is obtained if the electricity price effectively jumps to the VOLL when demand exceeds available capacity. In that sense, the regulator of the power system should correctly estimate the VOLL based on consumers' preferences and should allow for hourly prices reaching this value.

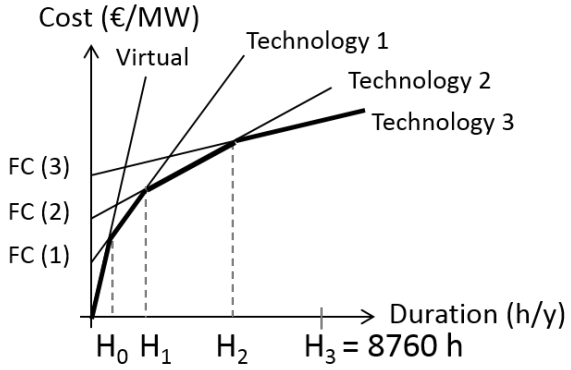
The screening curve approach introduced in section I.1.2 graphically illustrates how price signals emanating from forward day-ahead power markets can trigger investments in electricity generation in the reference energy-only design. The bottom graph of figure I.4 shows the infra-marginal (and scarcity) rents for the different technologies obtained from the price duration curve. Firstly, to invest in peaking units which have the highest marginal generation cost among the different technologies, it is necessary that the hourly price is higher that the marginal cost of peaking units during a number of hours[11] to ensure fixed cost recovery. In other words, generators would invest in peaking units if the annual scarcity rent ($R1$ in figure I.4) exceeds or equals the annualised fixed cost of peaking units. Secondly, this reasoning can be transferred to other technologies. Generators are likely to invest in a given technology if its anticipated infra-marginal (and scarcity) rents, obtained from the price duration curve in the energy-only reference design with marginal cost pricing as illustrated in figure I.4, allow for the recovery of its annualised fixed cost. Thirdly, the choice between the technologies depends on the number of running hours. Indeed, the top graph in figure I.4 allows to estimate the least cost technological choice given the number of running hours within the year as illustrated by the envelope bold curve[12]. Finally, under assumptions of pure and perfect competition with perfect anticipation of the future by generators, the price signal emanating from marginal cost pricing ensures that, on the long-term, investment decisions lead to the optimal generation[13] mix as defined in section I.1.2.

[11] This would happen when the hourly inelastic demand exceeds available capacities resulting in price spikes in relation to the willingness to pay of consumers during these extreme peak events.

[12] For example, for a number of running hours between $H1$ and $H2$, technology 2 is less costly than technologies 1 and 3. (See top graph of figure I.4.)

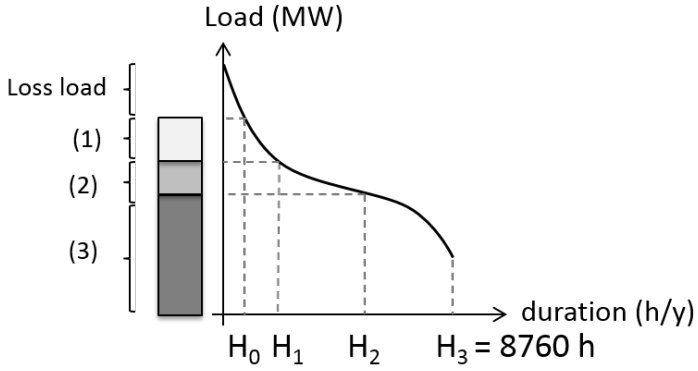
[13] Indeed, this can be illustrated graphically thanks to top graph of figure I.4: the characteristic line of a given technology can be interpreted as its total annual cost (annualised fixed costs and generation costs)

Annual total cost (€/MW.year)



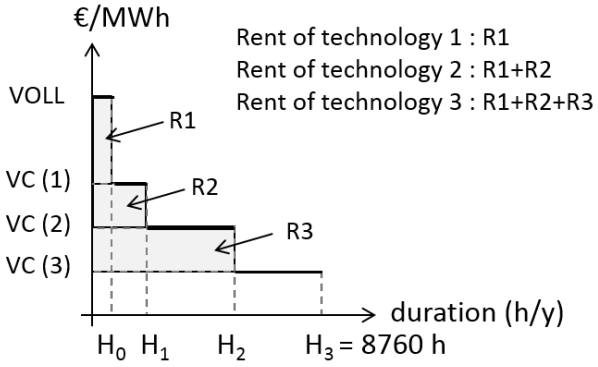
→ Optimal annual duration time of each technolgy.

Load duration curve (MW)



→ Optimal generation mix.

Price duration curve (€/MWh)



→ Infra-marginal (and scarcity) rents.

FIGURE I.4: Triggering investment decisions based on an estimation of infra-marginal rents by the screening curve method.

Translating this theoretical functioning to real power markets can be challenging given that real markets can differ from the theoretical pure and perfect competition paradigm. In addition, generators may face difficulties in perfectly anticipating the future and thus, they may take their decision according to their level of risk aversion. Then, the question to be addressed is whether the price-signals emanating from day-ahead power markets are sufficient in practice to ensure a correct level of installed capacity compared to the electricity load demand.

I.2.2 Limits of the long-term coordination by the energy-only market

Despite the theoretical ability of liberalised power markets to trigger a socially-optimal level of capacity, in practice, there are large concerns about the efficiency of an energy-only market. In particular, there is a wide economic literature on the so-called market-failures of the canonical energy-only market.

The *missing money* problem for peaking plants

The benchmark energy-only market is largely criticised in the literature for not being able to provide the correct level of installed capacity in practice. This is known as the *missing money* problem which is defined by Cramton and Stoft (2006) as the fact that "when generating capacity is adequate, electricity prices are too low to pay for adequate capacity". More specifically, the *missing money* refers to a lack of energy revenues to cover the costs of generation units in a situation of correct level of capacity in terms of reliability standards (Hogan, 2005). However, it is important to mention that it is perfectly normal that in case of overcapacity, power plants suffer from a lack of remuneration to recover their costs; and this should not be referred to as *missing money*.

In the literature, the existence of the *missing money* is explained by at least three main factors:

- the market price rarely jumps to the VOLL in practice because of an explicit or implicit price cap;

expressed as a function of running hours (in x-axis) whereas the bold envelope curve exactly corresponds to the revenue of a power plant expressed as a function of running hours under the assumption of (i) hourly prices defined on the marginal cost on each hour and (ii) optimal generation mix.

- risk aversion and access to imperfect information of investors can lead to underinvestment in peaking units, for which the revenues are very volatile;
- generation units have typical power size, thus investors make discrete choices.

These three elements are further discussed below in order to clearly identify how they affect private investment decisions.

- **Hourly electricity prices during peak hours**

In the reference energy-only market, a first difficulty lies in the definition of the market price when a fraction of the demand remains unserved. In this case, the electricity price should theoretically jump to the VOLL in order to provide correct price signals for investments to meet the optimal generation mix on the long-term (Stoft, 2002). More specifically, the VOLL can be defined as "the price that an average customer would be willing to pay to avoid an involuntary interruption of electricity supply" (IEA, 2016) and it is expressed in €/MWh. In practice, the theoretical peak-load pricing suffers from two main caveats: (i) the VOLL is challenging to estimate and may vary according to different parameters as for example the preferences of the different consumer groups and (ii) generators may be tempted to exercise market power during peak hours in order to increase their scarcity rents.

Firstly, the VOLL is particularly challenging to estimate. Its value may depend on at least four parameters: (i) the time at which the outage occurs, (ii) the duration of the outage, (iii) the consumers affected and (iv) the duration between the notification of the outage and the effective outage. In addition to this difficulty of defining properly the VOLL, its estimated value may differ depending on the method adopted. Among the different econometrics approaches that can be employed to estimate the VOLL, the most common are revealed preferences, stated choice experiment, macroeconomic analysis and case study analysis. As an illustration of the variation that may arise in the estimated values of the VOLL, London Economics (2013) estimates the VOLL for Great Britain by a stated preference choice experiment in terms of willingness-to-pay and willingness-to-accept and obtains estimations that vary from £ 208/MWh to £ 44,149/MWh. In the end, their report recommends a peak winter workday VOLL of £ 10,289/MWh for domestic users and £ 35,488/MWh for for small and medium sized businesses.

Secondly, the benchmark energy-only market with scarcity pricing supposes that, during few hours in a year, electricity prices can reach high values in the magnitude of € 10,000/MWh in accordance to the consumers' willingness to pay to be supplied during extreme peak periods. This does not only increase volatility of energy revenues leading to higher risks for investors but also generators may be tempted to exercise market power during these few peaking hours with very high prices. Moreover, regulators cannot easily distinguish between efficient scarcity pricing and exercise of market power (Cramton and Ockenfels, 2012).

Thus, the twofold regulators' objective of reducing the exercise of market power by generators and controlling electricity prices for end-consumers explains their decision to impose explicit price cap on most energy markets[14]. For that reason, in most countries, electricity wholesale prices are capped to a value which is significantly lower than the estimated VOLL. For example, in France, the VOLL is estimated to € 26,000 /MWh RTE (2011) while the price cap is defined at € 3,000 /MWh on the day-ahead market and € 10,000 /MWh on the continuous intraday market and on the balancing market. Only few countries have implemented scarcity pricing: ERCOT (Texas) which had increased the price cap from $ 7,000 /MWh to $ 9,000 /MWh in 2015; New-Zealand with prices up to $ 20,000/MWh; and West Australia with a price cap set to $ 13,500 /MWh (the value is adjusted annually).

The existence of price cap is pointed out as a main cause of underinvestment in electricity generation because it impedes the scarcity pricing and scarcity rents to be used to cover fixed costs of peaking units (Joskow, 2006a, Fabra et al., 2011). In addition, even if there is no explicit price cap on the electricity market and even if the energy market delivers adequate remuneration, the sole belief of investors that the market does not provide adequate remuneration can be sufficient to explain the *missing money* under the form of *missing market* (Newbery, 2015).

Moreover, the theoretical effectiveness of the energy-only market with VOLL pricing is difficult to transfer to a context of interconnected power markets. Indeed, if the estimated VOLL varies across the different interconnected zones, regulators have to find a common definition of the VOLL but then, the resulting interconnected power system

[14]It is important to dissociate regulatory price cap and technical price cap. Indeed, in several western European countries, the price cap is more technical in the sense that the power exchange operator, in accordance with regulators, aims to protect small suppliers against sky-rocketing price spikes.

is unlikely to be optimal at national levels and redistributive effects may arise between the different market areas.

- **Risk aversion, imperfect information and regulatory risks**

Even though the energy-only market delivers adequate remuneration to theoretically trigger investments in adequate level of capacity, risk aversion of private investors and imperfect information can justify underinvestment in peaking units and the existence of high risk-premiums (Rodilla and Batlle, 2012, Cramton and Ockenfels, 2012, Neuhoff and De Vries, 2004). Indeed, with this benchmark market design, revenues of peaking units depend on the frequency and magnitude of price peaks and so, these revenues are highly volatile. More specifically, as the society as a whole (represented by the regulator or the social planner) could also be risk averse, risk aversion of investors makes the energy-only market inefficient compared to a social planner if their level of risk aversion is higher than the one of the social planner in accordance with social preferences.

In addition, some analysts suppose that the underinvestment in electricity generation is mostly due to strategic behaviours rather than the existence of a price cap, given that producers are perfectly informed and could benefit from adequate and complete future markets to hedge their investment risks (Léautier, 2016). On the contrary, others consider that producers do not have access to perfect information and that uncertain regulatory interventions further disrupt the situation by increasing risks for investors and thus impeding the well functioning of the energy-only market (Cramton and Ockenfels, 2012). These regulatory interventions generally focus on limiting high energy prices and promoting the development of certain technologies (renewables in most cases).

- **Discrete power sizes of generating technologies**

In a perfect energy-only market, the existence of typical discrete power sizes for the various generating technologies can explain that the capacity adequacy target is not reached at all time. Indeed, depending on these typical power sizes and depending on the size of the system, correct market signals can fail to ensure capacity adequacy simply because it is not possible to build a single MW of a generating technology (Rodilla and Batlle, 2012). This is known as the *lumpiness* of investments, meaning that there is a minimum feasible power size that should be respected in practice. Besides, the discrete power sizes of generating technologies also explain that investors tend to underinvest rather

than overinvest even under the assumption of perfect foresight, perfect competition and perfect information (Keppler, 2014).

In addition, this effect of the discrete power sizes can continue to prevent the system from reaching the socially-optimal level of installed capacities even with the addition of a capacity mechanism. A solution to significantly decrease the lumpiness of investments lies in encouraging DR programs, which available capacity can be tailored with a lower capacity step.

Investments in capital intensive equipments

While peaking units suffer from market failures that directly impact their installed capacity and the resulting capacity adequacy of the system, other technologies can also face specific market failures. In particular, this is the case of capital-intensive equipments including base-load plants but also Low-Carbon Technologies (LCT) and Renewable Energy Sources of Electricity (RES-E), for which investments can be reduced in relation to investors' risk aversion, imperfect information and regulatory risks as explained above in the case of peaking units.

In the theoretical reference energy-only market, if generators are not able to bear investments risks as it can be the case for capital-intensive equipments, the previous vertical integration could be replace by bilateral contracts between generators and retailers (or large consumers) through multilateral markets for spot trading and through financial markets for hedging arrangements (Joskow and Schmalensee, 1983). This should help generators to invest in capital-intensive power plants despite the high associated investment risks. However, this theoretical paradigm supposes the completeness of markets including financial hedging products with long maturity (IEA and NEA, 2007).

In practice, forward day-ahead markets seem to be insufficient to to hedge against all generation risks suggesting that a balanced combination of vertical integration and long-term arrangements is superior to the two extreme situations, namely an energy-only market without long-term contracts on the one hand, and vertically integrated utility monopoly on the other hand (Chao et al., 2008). But, in most countries, there is no financial market to propose long-term hedging products to generators. Consequently, generators are incentivised to invest in equipments with low up-front capital costs as

for example Combined Cycle Gas Turbine (CCGT) rather than capital-intensive technologies. Besides, CCGTs also bring advantages for investors in terms of correlation between hourly market prices and their variable cost, for a significant number of hours when CCGT is the marginal technology. Among others, Roques et al. (2008) and Roques (2011) highlight these effects based on a modelling of optimal portfolio choices.

* * *

In sum, several market failures of the energy-only market are addressed in the literature among which the most frequently cited are (i) the existence of explicit or implicit price caps that prevents energy prices to reach high values needed to ensure capacity adequacy, (ii) risk aversion and imperfect information which can limit the willingness of investors to build peaking units or LCTs and (iii) the lumpiness of investment decisions which further complicates the reach of the theoretical long-term equilibrium. Market failures can impede investments in peaking units resulting in capacity adequacy issues but also investments in capital-intensive equipments including conventional base-load plants and most LCT including RES-E.

I.3 Investments in capital-intensive equipments in the context of environmental and climate policies

In recent years, "energy transition" has become an ever-present concern of energy policies. To put it simple, the energy transition can be defined as the evolution of both (i) energy generation toward low-carbon technologies and (ii) energy uses including more energy efficiency. It involves all types of energies but it also concerns the transportation and buildings sectors. The energy transition has gained in audience because it appears as a reasonable solution to mitigate climate change observed by scientists and related to anthropogenic Greenhouse Gas (GHG) emissions. Environmental issues directly impact the economy as a whole and more particularly the energy sector. Indeed, in its fifth report (IPCC, 2014), the intergovernmental panel on climate change proposes several approaches to mitigate climate change's risks among which economic options including pricing environmental externalities (GHG emissions, ecosystem services), financial incentives, and specific insurance or risk pools to cope with financial consequences of climate change.

Concerning power systems, energy transition can include (i) a shift from conventional thermal technologies to Low-Carbon Technologies (LCT) and Renewable Energy Sources of Electricity (RES-E) which can be partly done at decentralised level, (ii) an increase of energy efficiency, (iii) an evolution of the grid to manage local decentralised sources of generation and (iv) an increase role of consumers in real-time. Besides, the electricity consumption profile can also evolve in consequences of new electricity uses (for example, electrical vehicles).

In this context, LCTs including RES-E are key options for climate change mitigation. Indeed, compared to thermal technologies and in particular compared to coal-fired power plants, LCTs including RES-E (among which hydro power, wind power and solar) are characterised by very low (or even zero) emission factors. Besides, energy independence and energy diversification are supplementary justifications to promote local RES-E.

This section presents the challenges posed by investments in LCTs including RES-E, among which variable generation plants, in the context of environmental and climate policies.

I.3.1 Difficulties in investing in renewables and low-carbon technologies

Today, the large progress in LCTs and RES-E suggests that there are no significant technological barriers to impede the development of these technologies (Neuhoff, 2005). In particular, this is valid for on-shore wind power, geothermal and solar photovoltaic. However, their deployment is still limited in most countries and often depends on economic instruments in place to foster investments in these particular technologies. This sub-section reviews the difficulties faced by investors in LCTs including RES-E that can partially explain their limited development.

In most countries, hydroelectric power enjoys a different situation compared with most variable RES-E. Indeed, hydroelectric economic potential has often already been developed close to its full potential in many mature markets.

Incompleteness of markets for investing in capital-intensive technologies

Compared to conventional thermal technologies, LCTs and RES-E are characterised by very high upfront investment costs and low variable costs. Thus, this cost-structure reinforces the difficulties faced by investors because of the incompleteness of electricity markets, in particular the inability of electricity markets to provide acceptable long-term contracts to cover total costs with an acceptable risk sharing between generators and consumers (Finon, 2013).

Dynamics externalities of learning

When designing technologies' characteristics, there is an inherent trade-off between technical options at disposable and acceptable costs. Regarding LCTs including RES-E, this effect can justify to consider positive externalities of a given technology (related to innovation and technological dissemination) in addition to the classical environmental positive externalities of these technologies (Jaffe et al., 2005). However, when these externalities in terms of innovation and technological dissemination are not internalised in power markets, incentives to invest in LCTs can be reduced compared to the socially-optimal level.

Today, some LCTs including some RES-E are still immature technologies which are at different stages in terms of commercial maturity. As in other sectors, these new technologies may face significant barriers which can come out from several elements of power systems (Neuhoff, 2005). Firstly, the electricity sector is characterised by large typical power sizes for conventional technologies and large time horizon that increase risks face by new technologies. Secondly, as in most sectors, technology spillover can benefit to all generators and consequently, there can be few incentives to invest in R&D (Watanabe et al., 2001). However, patent system seems not adapted because it can be challenging to protect a new engineering technology that can be circumvented rapidly and because these innovations generally involve a consortium of firms with different knowledges (Watanabe et al., 2001).

Lower economic value of undispatchable RES-E

Most RES-E are based on the use of natural energy flows (for example, wind, solar or tidal energies) and thus, these variable technologies are characterised by an undispatchable[15] energy generation depending on weather conditions. This feature can lower their economic value in the context of liberalised markets with private generators making their decisions based on anticipated revenues.

The value factor of undispatchable technologies allows for the comparison between their remuneration from the market and the remuneration that would be obtained by selling an equivalent volume but with a dispatchable power plant. In that sense, the value factor estimates the remuneration penalty due to the specific load profile of an undispatchable technology. This value factor is defined as the ratio between the RES-E-weighted[16] average market price and the time-weighted average market price. Different studies estimate this value factor for intermittent renewable technologies (Green and Vasilakos, 2011b, Hirth, 2013).

Based on a model calibrated for North-western Europe (Germany, Belgium, Poland, The Netherlands and France), Hirth (2013) estimates the value factors of on-shore wind and solar for different levels of market share. For on-shore wind, the estimated value

[15]Large hydraulic tanks and biomass plants are renewable and dispatchable technologies. Consequently, the following discussion does not apply to these technologies.

[16]Whereas the time-weighted average price is the classical mean value of hourly prices, the RES-E-profile weighted average price corresponds to the mean price received by a RES-E generator having the average RES-E profile.

factor is 1.1 for low penetration levels (less than 5% of market share) due to a positive correlation between wind factors and electricity consumption, but then the value factor decreases to 0.5 at 30% penetration. For solar, the analysis carried out by Hirth (2013) suggests that the value factor is significantly lower than the one of wind: a value factor slightly below 0.5 is estimated for a 15% market share of solar.

Besides, the value factor of undispatchable technologies immediately decreases if the installed capacity of these technologies increases. Thus, when more variable renewables with zero-variable cost are added to the system, their profitability can be significantly reduced. This so-called "self-cannibalisation effect" of variable renewables is identified in several studies (Lamont, 2008, Hirth and Müller, 2016) and in chapter III.

Risks borne by investors in RES-E and LCT

All technologies, either renewables or conventional ones, face risks and uncertainties about the future evolution of the power system and thus, about their profitability. However, LCTs including in particular RES-E are more exposed to risks and uncertainties than other conventional technologies (Grubb and Newbery, 2007): fossil-fuel power plants clear the market most of the time and thus, investors in these technologies are easily hedged against the price uncertainties of fuels. On the contrary, LCTs including RES-E face high price uncertainties which are not linked to their variables costs. This is also the case for nuclear power (Roques et al., 2006a).

* * *

In the context of climate change mitigation and energy transition, LCTs including RES-E now seem indispensable to meet the environmental targets. However, these technologies face several difficulties previously mentioned that impede their market-based development. While carbon pricing could be a solution to promote their development, specific out-of-market arrangements are often implemented in practice.

I.3.2 Regulatory failures of the carbon pricing

Classical arguments in favour of carbon price to trigger entries of LCTs including in particular RES-E as soon as these technologies are close to commercial competitiveness

to the detriment of the use of specific mechanisms are still supported (Crampes, 2014). On the broader level of reducing CO_2 emissions, it is also argued that carbon pricing (through carbon tax or cap and trade system) is the best option to mitigate climate change (Gollier and Tirole, 2015) by contributing to trigger investments in LCTs in the different sectors. Indeed, in power systems, introducing a carbon price (either by a carbon tax or by an emissions trading scheme) have a long effect on the generation mix in addition to the short-term effect of substitution[17]. Indeed, the introduction of a carbon price can modify the relative competitiveness of the different technologies in favour of LCTs including RES-E or eventually DR programs rather than polluting thermal technologies, hence a change in investment decisions and finally in the generation mix. When the short-term effect has totally been exploited, the long-term effect remains the only solution to further decrease the CO_2 emissions of power systems. Thus, it is particularity crucial to understand how the introduction of a carbon price (or other measures in favour of LCTs including RES-E) can trigger private investments towards commercially mature LCTs.

This being said, some practical conditions are required to ensure the ability of a carbon price to trigger investments in LCTs including RES-E, given their high upfront investment costs. The carbon price should send a credible and stable signal to enable investors to anticipate their revenues on the long-term. In Europe, the EU Emissions Trading System (EU-ETS) experience suggests that these practical conditions are hardly reached in practice because of uncertainties: economic conjecture, unexpected effects of overlapping policies focused on renewables and energy efficiency (Schmalensee and Stavins, 2015). The European experience has been characterised by (i) a surplus of allowances in phase I (2005-2007) causing a decrease in the carbon price, (ii) an unfavourable economic conjecture in phase II (2008-2012) which partly explains the low carbon price's level. Despite the reforms implemented for phase III (2013-2020), the observed carbon price is still below € 10 /tCO_2. At the end of the day, the effectiveness of the EU-ETS in

[17]Also called merit-order effect, the short-term effect of introducing a carbon price corresponds to the increasing use of generation units with low levels of GHG emissions as a consequence of adding the carbon cost of emissions into the variable cost of each technology. In particular, increasing the carbon price can provoke a switch in the relative marginal costs of gas and coal. Switching these two technologies is particularly relevant because the emission factor of coal-fired power plants is over twice as much as the one of combine cycle gas turbines. Climate Strategies (2015) estimates the potential decrease in CO_2 emissions triggered by the sole merit-effect of a high carbon price in a static analysis for seven countries in Europe and shows that for the central scenario (based on recent gas and coal prices), a carbon price of € 40 per ton of CO_2 reduces the CO_2 emissions by 27% (corresponding to annual savings of 150 Mt CO_2). The countries considered in Climate Strategies (2015) are the following: UK, Germany, Poland, Italy, pain, Czech Republic and Romania.

triggering investments in LCTs, including in particular RES-E, remains unclear (Laing et al., 2014, Brohé and Burniaux, 2015).

As a result of the worldwide experiences with cap and trade, for any regulator willing to implement an efficient emission reduction policy, it now seems a necessity to use specific instruments devoted to the promotion of clean technologies, or to implement a carbon price floor with a good level of credibility and foreseeability (Branger et al., 2015).

I.3.3 Out-of-market arrangements to support renewables and low-carbon technologies

From an economic perspective, the climate change induced by GHG emissions can be described as a negative externality of human activities, while the climate can be considered as a public good with the two properties of non-rivalry and non-excludability (Nordhaus, 1991). Historically, emitting GHGs was totally free and thus, this effect was not taken into account in economic activities. In this respect, environmental and climate policies firstly aim at internalising environmental externalities in economic decisions.

The problem of public good and free-ridding is extensively addressed in environmental economics since the seminal article of Hardin (Hardin, 1968). Classically, three types of solutions can be implemented to protect private goods from its overexploitation: (i) the regulatory instrument which consists in establishing precise rules to limit a given negative externality, (ii) the tax instruments or (iii) the introduction of transferable rights that can be traded on a dedicated market. Besides these direct methods, indirect methods can be implemented including research and development funding, below-cost of infrastructures or services (Batlle et al., 2012).

The design of RES-E promotion policy is central to the current European energy debate and has been questioned in a number of academic works (Menanteau et al., 2003, Palmer and Burtraw, 2005, Klessmann et al., 2008). Discussions on the design of a specific mechanism to enhance the development of LCTs include different aspects: price-based versus quantity-based instruments, technological-specific or technological-neutral mechanisms,

centralised or decentralised coordination. Besides, setting the objectives of environmental policies[18] is particularly challenging given the complexity in assessing environmental effects and given the strong lobby of big companies. Finding acceptable objectives can depend on at least three dimensions: (i) technical feasibility, (ii) cost affordability and (iii) effectiveness in addressing environmental issues.

Different support mechanisms

Environmental and climate policies can be based on (i) classical instruments to internalise environmental externalities (taxation or tradable permits) and (ii) specific policies devoted to the development of certain environmentally-friendly technologies. Table I.2 presents the four most common support mechanisms than can be found in the literature. Among these various mechanisms, Feed-In Tariffs (FITs) (often combined with priority of access and low transmission charges) appear to be the preferred instrument in practice and have proven to be efficient to trigger the development of LCTs including variable RES-E (Menanteau et al., 2003, Lewis and Wiser, 2007, Alagappan et al., 2011). However, some academics and institutions advocate that the further integration of variable renewables to power systems should now be increasingly based on market signals[19] (Hiroux and Saguan, 2010, Batlle et al., 2012, European Commission, 2015). This change of RES-E support schemes is in dispute among academics. In particular, in an open letter addressed to the European Commissioner, Fabra et al. (2014) claim that market premium that would replace the previous fixed FIT "is likely to increase financing costs and might have negative effects on the efficiency of short-term markets and effectiveness of forward markets". This point of view is also supported by Newbery (2011), who argues that market-based supports are more risky resulting in an increased

[18] At the European level, the so-called 20-20-20 targets defined in the directive 2009/28/EC (European Commission, 2009) consist in three binding goals to be achieved by 2020: (i) a decrease of 20% of GHG emissions compared to 1990's levels, (ii) 20% of energy generated by renewables and (iii) an improvement of 20% in energy efficiency compared to 1990. Even more ambitious targets are already set for 2030 (European Commission, 2014c): (i) a decrease of 40% of GHG emissions compared to 1990's levels (binding target), (ii) a minimum 27% share of renewables in energy consumption and (iii) a minimum improvement of 27% energy savings compared to the business-as-usual scenario. Reaching these objectives would certainly require to implement efficient environmental and climate policies.

[19] In Europe, guaranteed FITs become unlawful from 2016 in application of the Guidelines on State aids (European Commission, 2014b). In this context, most European countries tend to shift to Feed-In Premiums (FIPs) (Germany, France, UK). Continuing this trend towards a significant evolution of support mechanisms for renewable technologies, the European Commission suggests to improve market signals as stated in its public consultation on a new energy market design (European Commission, 2015): "What needs to be done to allow investment in renewables to be increasingly driven by market signals?"

	Description	Characteristics
Feed-in Tariffs	The producer receives a fixed price (in €/MWh) for each generated MWh.	Price-based, decentralised, technology-specific. Ex: Germany, France, Spain.
Feed-in Premiums	The electricity is sold on the market. The producer receives a variable or fixed premium (in €/MWh) for each MWh sold on the market.	Price-based, decentralised, technology-specific.
Renewable obligations	Electricity suppliers must respect a given share of green energy. Eventually, green certificates can be tradable.	Quantity-based, decentralised, technology-neutral.
Auctioning for long-term contracts	Call for tenders are carried out periodically by a neutral agency. The long-term contract can remunerate either the investment or the volume of produced electricity.	Quantity-based, centralised, technology-neutral or technology-specific. Ex: Austria, Italy, United Kingdom.

Note: Examples apply for the period before 2016. In Europe, guaranteed FITs are not lawful any more after 2016 (European Commission, 2014b).

Table I.2: Presentation of the four most common support mechanisms.

discount rate and significant extra-financing costs. Quirion (2016) proposes a synthesis of this controversy on RES-E support schemes and concludes that there is no clear economic justification to prefer premium to fixed tariff.

At least four dimensions can be introduced to characterise these different support mechanisms: (i) remuneration of the investment costs or remuneration of the generated quantity of electricity, (ii) quantity-based or price-based, (iii) technology-specific or technology-neutral, and (iv) centralised or decentralised coordination. Besides, the different support mechanisms can also differ in the risk borne by investors.

- **Energy or capacity remuneration**

A support mechanism can provide a subsidy either (i) to the generated volume of electricity for a given number of years or (i) to the installed capacity through a subsidy of the investment cost. Given that a trade-off between capacity and generated energy exists for each technology, the technology choice can be significantly influenced by the electricity product which is targeted by the support mechanism.

- **Quantity-based versus price-based instruments**

In public economics, a public policy objective can be reached either by a quantity-based instrument or by a price-based instrument. This concerns both conventional environmental policies and specific policies focused on the promotion of clean technologies. On the one hand, a **quantity-based instrument** explicitly defines the objective in terms of a quantity to be reached. In matter of environmental policies, a quantity-based instrument corresponds to the setting of the environmental objective in terms of CO_2 emissions or share of green energy, for a given year. On the other hand, a **price-based instrument** explicitly sets the price rather than the quantity. The price should be correctly defined in order to reach the fixed objectives. Thus, in matter of climate policies to reduce GHG emissions, a price-based environmental instrument can introduce a carbon price. In the case of clean energies policies, it can introduce a given remuneration (generally an energy remuneration) for specific LCTs and in particular RES-E.

The question between price-based and quantity-based economic instruments is particularly discussed for designing policies of climate mitigation. In theory, cap and trade (quantity-based instrument) or Pigouvian taxation (price-based instrument) are equivalent. However, one can be preferred to the other depending on the uncertainty and elasticity of cost function compared to the benefit function (Weitzman, 1974). The underlying idea is to compare the consequences of uncertainties and small errors in the quantity or in the price on the results of the regulation to determine which error leads to the smallest deviation of the result. As an initial approach, quantity-based mechanisms and price-based mechanisms can be equivalent but only if there is perfect information and no uncertainty. On the contrary, when asymmetric information and uncertainty are assumed, price-based mechanisms are best options than quantity-based mechanisms if the marginal benefit curve is flatter than the marginal costs curve (Weitzman, 1974, Hepburn, 2006).

In the case of GHG emissions, the slope of the marginal cost curve is actually steeper than the slope of the marginal benefit curve. Thus, price-based instruments should be preferred as confirmed by Hoel and Karp (2001) and Pizer (2002). Figure I.5 illustrates the situation of a marginal cost curve with a steeper slope than the one of marginal benefit curve. Then, in this case, the optimal tax (T^*) and quota (Q^*) are defined on the basis on the real marginal cost curve. But, if there are uncertainties on the costs and thus the marginal cost curve is different from the real one, the regulator would define

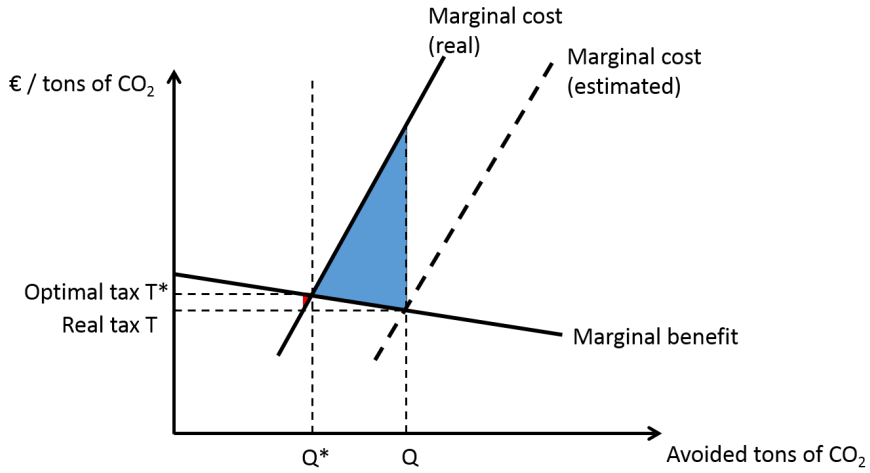


FIGURE I.5: Efficiency of price-based and quantity-based mechanism in reducing emissions.

the tax T or the quota Q rather than the optimal values T^* and Q^* respectively. The figure illustrates than in this case, the economic inefficiency induced by the quota (blue area) is greater than the one induced by the tax (red area).

Transposing this reasoning to policies of RES-E promotion, the quantity-based mechanism seems theoretically the best option to meet the environmental target because the social benefit curve is quite flat. However, price-based instruments are often preferred in practice in most countries (Menanteau et al., 2003) mostly because of their advantages for risk management of RES-E investments, and because of a greater experience and feedbacks to a lesser extent. Indeed, price-based instruments (FITs, FIPs, contracts for difference) guarantee long-term revenues to investors and thereby decrease risks related to capital cost recovery, whereas quantity-based instruments as obligations of green certificates on suppliers do not offer this long-term dimension regarding the decrease of revenues' risks for investors.

- **Technology-specific versus technology-neutral support mechanisms**

Support mechanisms designed to trigger investments in LCTs including variable RES-E can be either technology-neutral or technology-specific which involves to implement a specific mechanism for each subsidised technology. A number of academic works are in favour of technology-neutral mechanisms rather than technology-specific ones (Lehmann and Söderholm, 2016) because of the better cost-effectiveness of technology-neutral mechanisms. However, others advocate that technology-specific are still needed

as the different technologies are not at the same stage of maturity (Neuhoff, 2005). In particular, it can be necessary to directly incentivise research and development activities for new emerging technologies in order to solve the positive externalities issues cited by Jaffe et al. (2005).

Thus, the choice between technology-specific versus technology-neutral support mechanisms, devoted to investments in LCTs including RES-E, mainly depends on the relative maturity of these different technologies. At the European level, the European commission clearly claims to switch towards technology-neutral market-based renewables support schemes (European Commission, 2014a,b).

I.4 Capacity adequacy issues

Power systems aim at delivering electricity to end-consumers with what could be simply called "a good quality of service"[20]. In the technical lexicon, the security of electricity supply is a systemic property of power systems which characterises this so-called "good quality" and which results from the interaction of the different activities of generation, distribution, transport and supply and which encompasses different time scales (Roques, 2003).

Two decades after the liberalisation of the European electricity sector, there are still large concerns about the capability of the energy-only market to guarantee the security of electricity supply. Indeed, most of European countries have benefited from over-capacity inherited from former monopolies, so that the long-term function of energy markets was not central to the debate on market design. But today, the long-term coordination of investments is at the center of the policy debate in Europe. There are increasing concerns about the security of electricity supply in European countries for different reasons, among which ageing power plants to be replaced (e.g. in Great Britain), political and legal phase-out of nuclear and coal plants (e.g. Germany, Great Britain), increasing share of variable renewables (e.g. in Germany, Italy, Spain) or specific peak-demand challenges (e.g. in France). In this context, growing interest is given to the design of an appropriate market to ensure mid-term and long-term capacity adequacy with respect to reliability preferences of consumers.

This section addresses the particular challenge posed by capacity adequacy. The first sub-section presents different ways to deal with the capacity adequacy objective. Then, the second sub-section provides elements on designing capacity mechanisms.

I.4.1 Defining capacity adequacy

In most electricity markets, end-consumers have no or very few incentives to reveal their preferences in electricity reliability. Because of this caveat, reliability is generally considered as a public good (Cramton and Ockenfels, 2012, Finon and Pignon, 2008) which is both non-excludable and non-rivalrous. More specifically, reliability includes

[20]In Europe, the last notable event of "blackout" happened on November, the 4th, 2006. It causes a split of the European grid into three areas. It was mainly attributed to the non fulfilment of the N-1 criterion in Germany and to the insufficient inter-TSO coordination (UCTE, 2007).

two components which differ on their related temporality (see table I.3): (i) short-term security of supply which aims at guaranteeing that the system is able to face a number of unfavourable situations[21] in real-time and (ii) long-term capacity adequacy between the installed power plants and the electricity demand. Oren (2005) considers that only security is a public good while adequacy can be treated as a private good under the assumption that consumers can choose their level of insurance against electricity outages. However, this paradigm could be possible only thanks to a great enhancement of measure and control systems, but it is rarely the case in current power systems. In absence of a deployed technology to curtail customers based on their reliability preferences, reliability including both security and adequacy can be considered as a public good. Thus, this justifies the need of additional capacity mechanism to ensure capacity adequacy as this function is not achieved by the sole energy-only market as discussed in I.2.

In this context, ensuring capacity adequacy is one of the key objectives when designing market architecture. To this purpose, some countries clearly define capacity adequacy standards (also called reliability standards). The most common criteria used to define capacity adequacy standards are presented presented below:

- **Loss Of Load Expectation** (LOLE) is the number of hours of outage that are expected on average over a number of possible scenarios for a given year[22]. This reliability criterion only focuses on the duration of outage, while unserved energy demand is not considered. In practice, this criterion is used in several countries and in particular in Belgium, France, Great Britain and several states in the US (PJM, NYISO and ERCOT).
- **Loss Of Load Probability** (LOLP) corresponds to the probability of an outage expressed in percentage of total hours in a year. It is equal to the LOLE as previously defined divided by 8760. Just as the LOLE, the LOLP does not take into account the volume of unserved energy.
- **Expected Unserved Energy** (EUSE) is the energy that is expected to be unserved on average over a number of scenarios for a given year. This reliability criterion takes into account the magnitude of the event rather than its duration.

[21] Bompard et al. (2013) propose a detailed classification of the main factors that threat the security of supply. They identify that natural threat remains the main cause of blackouts.

[22] Here, the LOLE is expressed in hours per year. However, some prefers to make the distinction between the LOLE expressed in number of events per year and the so-called Loss of Load Hours (LOLH) expressed in hours per year.

- **Capacity margin** is a quantitative criterion which corresponds to the amount of excess capacity above peak demand, generally expressed in percentage of the peak electricity consumption.

In practice, reliability standards are generally defined at a national level. Depending on the country, capacity adequacy is not always reflected in reliability standards. Besides, in case a reliability criterion is defined, this bidding or non-bidding criterion varies across countries. At European level, reliability standards are far from being defined on a European-wide basis. However, in a context of interconnected electricity markets, harmonisation of generation adequacy criteria across Europe, as advocated by the European Commission (European Commission, 2013) and ACER (ACER (2013), see paragraph 54-I), would constitute a further step toward a common management of adequacy issues by a better functioning of the integrated European electricity markets.

Besides, energy-only markets can be explicitly or implicitly capped at a value lower than the Value Of Loss Load (VOLL) and thus they can fail to provide sufficient average scarcity rents for peaking units to guarantee capacity adequacy (section I.2). In this context, national regulators of many countries (especially countries with explicit reliability standards) have decided to introduce capacity mechanisms as a solution to enhance the functioning of energy systems in order to solve the *missing money* problem. This can be achieved by different approaches that are presented in the following sub-section.

I.4.2 Alternative capacity mechanisms

There is a wide literature about the choice for an efficient capacity mechanism[23] in the context of imperfect regulation due to a price cap in an energy-only market (Stoft, 2002, De Vries, 2004, Oren, 2005, Finon and Roques, 2013, Cramton et al., 2013). Some advocate that the energy-only market functioning can be enhanced so that the missing money would be solved without introducing supplementary mechanism (Shuttleworth, 1997, Hirst and Hadley, 1999, Hogan, 2005). Others support the introduction of capacity mechanisms to complement the energy market (De Vries, 2007, Finon and Pignon, 2008, Cramton et al., 2013, Keppler, 2014), eventually together with an improvement of the

[23]The term "capacity mechanisms" is used as the general term for these mechanisms that aim at guaranteeing a certain level of capacity adequacy. However, these mechanisms are also mentioned as "capacity remuneration mechanisms" and sometimes "capacity markets".

energy market functioning (Jaffe and Felder, 1996). In the following, main characters of different capacity mechanisms are presented before detailing economic criteria used to assess the efficiency of these mechanisms.

I.4.2.a Characters of the different capacity mechanisms

Capacity adequacy issues can be tackled by several alternative capacity mechanisms with different characteristics which are presented in numerous academic works (Pérez-Arriaga, 2001, De Vries, 2007, Finon and Pignon, 2008, Batlle and Rodilla, 2010, Finon and Roques, 2013) and reports (DECC, 2011, ACER, 2013, Cigré, 2016, IEA, 2016).

	Volume or price-based	**Capacity-wide (CW) or targeted (T)**	**Capacity product**	**Determination of capacity volume**	**Procurement**
Strategic Reserve	Volume	T	Physical	Central authority	Central authority
Ex Ante Capacity Obligation	Volume	CW	Physical	Central authority	Suppliers
Ex Post Capacity Obligation	Volume	CW	Physical	Each supplier estimates its required volume. Ex-post verification by the central authority.	Suppliers
Capacity Auction	Volume	CW	Physical	Central authority	Central authority
Reliability Options	Volume	CW	Financial	Central authority	Central authority
Capacity Payment	Price	CW or T	Physical	Central authority	Central authority
Capacity Subscription	Volume	CW	Physical	Each customer	Customers

Table I.3: Capacity mechanisms.
Terminology from Cigré (2016).

Among the various capacity mechanisms, a strategic reserve allows for the reservation of a small amount of generating capacities in return for an annual fixed payment, to provide an additional reserve. Usually, the reserved capacities are excluded from the merit-order during off-peak periods and are to be used only if necessary during peak events. A capacity obligation corresponds to the definition of a required installed capacity to be

reach through an obligation upon load service entities (or other individual entities). Many other capacity mechanisms have been proposed. Table I.3 briefly summarises the different capacity mechanisms explored in the literature by following the terminology used in Cigré (2016).

Each capacity mechanism can be described on the basis of (i) quantity versus price-based, (ii) targeted versus capacity-wide and (iii) centralised versus decentralised. Figure I.6 draws a classification of capacity mechanisms based on these three distinctions.

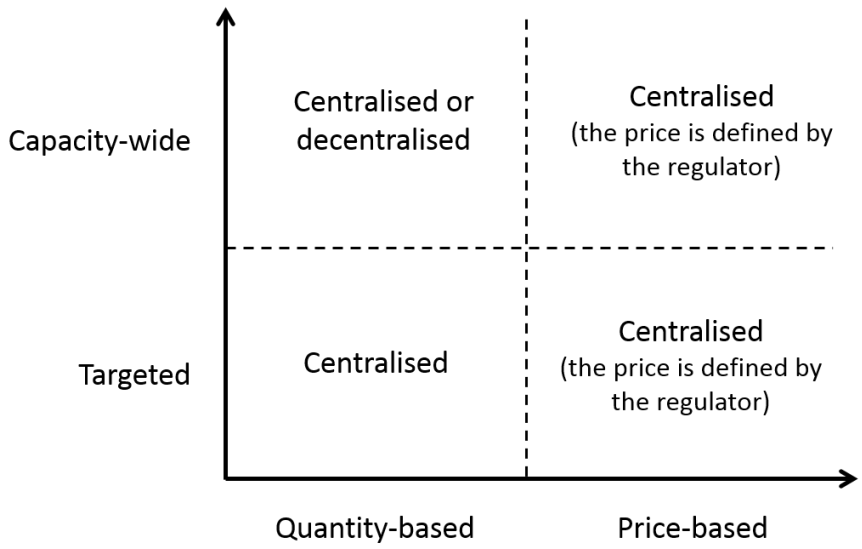


FIGURE I.6: Classification of capacity mechanisms based on three design's options.

Quantity-based versus price-based mechanism

A first distinction among capacity mechanisms is made according to their definition in quantity or in price (Batlle and Rodilla, 2010). Indeed, the objective of a capacity mechanism is to ensure a sufficient level of installed capacity to guarantee an adequate security of electricity supply. This can be achieved either by defining a quantity target or a capacity price. In this case, the choice between quantity-based or price-based instrument should be made based on the comparison between the cost of capacity procurement and the social benefit of reducing energy outages. Mixed instruments define both a capacity target and a capacity price in order to limit the cost of the measure for end-consumers.

As already stated in the discussion on renewable supports (section I.3), public policies based on quantity-based mechanisms or price-based mechanisms are equivalent but only if there is perfect information and no uncertainty. On the contrary, when asymmetric information and uncertainty are assumed, price-based mechanisms are best options than quantity-based mechanisms under the condition that the marginal cost curve is steeper than the marginal benefit curve (Weitzman, 1974).

In the case of capacity adequacy, the marginal social cost increases sharply with the level of electricity outages (RTE, 2011). On the capacity supply side, the marginal cost of installing new capacity corresponds approximately to the annualised fixed cost of peaking plants[24] and thus, the supply curve is pretty flat. Consequently, Finon and Pignon (2008) argue that quantity-based capacity mechanisms should be preferred by default because a small error in the definition of the capacity payment could lead to a large over or under-capacity compared to the socially optimal level.

Partial or total involvement of resources

To enhance capacity adequacy of power systems, capacity mechanisms can involve all installed capacities or only a small proportion of capacities (generally peaking plants). It constitutes a key feature of the market-design of capacity mechanisms (ACER, 2013).

On the one hand, a **targeted capacity mechanism** only concerns a part of installed capacities, while the rest of capacities take their remuneration from the sole energy markets. Strategic reserve is an example of targeted capacity mechanism. However, even before the introduction of capacity mechanisms, occasional tenders were already a targeted option let to national regulators to enhance capacity adequacy. On the other hand, a **capacity-wide mechanism** involves all installed capacities, including demand-response programs in some cases. Thus, all capacities can benefit from a capacity revenue besides its energy revenue.

Besides, various reasons can motivate to implement a capacity mechanism that distinguishes among technologies. In particular, environmental considerations can lead to exclude (or to decrease the capacity remuneration of) specific technologies from capacity

[24]The peaking unit is supposed to be the marginal technology to reduce electricity outage. The reality could be more complex if demand response is also considered as an option to do so. Moreover, here, the underlying assumption is that the marginal capacity will be useful during its whole life-time so that its annualised fixed cost is considered, rather than it total investment cost.

mechanisms as, for example, highly polluting equipments. The contribution of variable resources to the capacity adequacy of power systems is also very peculiar when compared to the one of conventional dispatchable technologies (Cepeda and Finon, 2013). Thus, the participation of variable technologies to a given capacity mechanism can be based on specific rules which take into account their variable nature.

Centralised or decentralised mechanism

Among capacity-wide mechanisms, a further distinction lies in the level of coordination or centralisation in the definition of the capacity adequacy target and, more importantly, in the procurement of capacities. In turn, targeted mechanisms are generally centralised (as for example, strategic reserve or one-off tenders).

- In a **centralised** quantity-based capacity mechanism, a national authority sets the volume of capacity to be reached and organises its procurement.
- In a **decentralised capacity mechanism**, each specified entity (generally the suppliers) must acquire a certain level of capacity certificates in relation to its total served load. Usually, a national entity defines the total volume to be procured (generally based on the reserve margin), or at least defines the methodology to be used by each supplier to estimate this volume.

I.4.2.b Assessment criteria to analyse capacity mechanisms

The choice of a given capacity mechanism is usually based on an assessment of its efficiency to solve the specific capacity adequacy issues of the considered area. To do so, different goals of capacity mechanisms are suggested in the literature (De Vries, 2004, Bushnell, 2005, Finon and Pignon, 2008). Table I.4 proposes a synthesis of several criteria for analysing capacity mechanisms, based on three main complementary assessment phases.

A first phase could aim at estimating the effectiveness of the capacity mechanism, in terms of the considered adequacy standards, in various contexts from an isolated market to the complex interconnected markets with different capacity mechanisms in place. As exposed in table I.4, different analytical steps can be differentiated. On the one hand,

Analysis angles	**Criteria**
1. Effectiveness in ensuring capacity adequacy	1.1 Adequate investment incentives (solving the *missing money* problem 1.2 Physical control over availability of generation plants during peak hours 1.3 Effectiveness in an isolated market 1.4 Effectiveness in an interconnected market 1.5 Consistency with the energy-only market 1.6 Institutional and practical feasibility
2. Cost efficiency	2.1 Is there a less costly alternative? 2.2 Effect on electricity price for end-consumers 2.3 Quantifying the increase in social welfare
3. Additional improvements	3.1 Effect on price and revenue volatility 3.2 Stimulation of demand-side participation (increase of price elasticity of electricity demand) 3.3 Effect on the exercise of market power 3.4 (Im)Possibility of free-riding

Table I.4: Analysis grid of capacity mechanisms

most of the proposed criteria can be evaluated by modelling tools (criteria 1.1 to 1.5). On the other hand, it is also necessary to validate the institutional and practical feasibility of the proposed mechanism (criteria 1.5 and 1.6).

Once the effectiveness of the mechanism is assessed, a second assessment phase could check if there is no other less costly mechanisms that provide the same effectiveness. In particular, three main axis can be analysed (see table I.4): the cost of the mechanism compared to alternative market designs, the effects on energy prices for end-consumers and the quantification of the social welfare improvement.

Finally, a last assessment phase could estimate what consequences are expected for the general organisation of the system and could assess the potential additional improvements for power markets. As presented in table I.4, various improvements can be analysed: the effects on volatility of generators' revenues (to be linked to the risk faced by investors and their level of risk aversion), the improvement on the demand-side by encouraging demand-response development, which is a very relevant step to solve the missing money, and the possibility of exercising market power and free-riding.

These criteria has been used in practice in numerous studies to evaluate and compare the different alternative capacity mechanisms. In particular, De Vries (2004) provides a

significant comparison of six capacity mechanisms based on criteria similar to the ones detailed above. Two major conclusions can be drawn from the comparison proposed by De Vries (2004): (i) capacity requirements and reliability contracts are more efficient in the stabilisation of investments (related to investment cycles) than capacity payments or strategic reserve, whereas (ii) capacity payments and strategic reserves benefit from a higher practical feasibility. This suggests that theoretical efficiency estimated by long-term power system modelling needs to be completed by practical considerations in order to ensure actual efficiency of the chosen capacity mechanism in practice.

In order to analyse a capacity mechanism according to these different criteria, it is necessary to model the energy market and the capacity mechanism accurately. Generally, all the criteria cannot be evaluated on a single modelling, and thus, many types of modelling can be involved to estimate the different aspects of the social efficiency of each capacity mechanism: in particular, optimisation under pure competition and different types of information, simulation model with bonded rationality. These different modelling possibilities are discussed in section II.2 of chapter II.

I.5 Synthesis of the chapter

This first chapter provides key elements of power systems before coming to market design issues. It highlights two key challenges for the long-term efficiency of power systems: (i) investments in capital-intensive Low-Carbon Technologies (LCT), including in particular Renewable Energy Sources of Electricity (RES-E), in the context of energy transitions, and (ii) capacity adequacy.

Electricity can be generated by different technologies, spanning from large conventional power plants to smaller decentralised ones. Each technology is characterised by its cost structure, its operational constraints to be respected in real-time and its environmental impacts. On the one hand, thermal conventional technologies are characterised by a cost structure which includes 15% to 40 % of fixed costs, a dispatchable generation with dynamic constraints and they may generate Greenhouse Gas (GHG) emissions. On the other hand, variable RES-E (as wind or solar) are characterised by a cost structure which includes roughly 100% of fixed costs, an undispatchable generation which depends on weather conditions and they have low GHG impact compared to conventional technologies based on burning gas, coal or diesel.

On the demand-side, the electricity load is still characterised by significant variations from hour to hour and by small price-elasticity. Indeed, small and medium-size end-consumers are rarely sensitive to the hourly electricity price because they mostly benefit from fixed hourly tariff (or two-price tariff with a distinction between peak and off-peak periods). Thus, the pattern of their consumption is primarily explained by their end-use applications of electricity, rather than by wholesale electricity prices. Regarding its long-term evolution, the electricity consumption has been roughly stable in most OECD countries since the economic crisis in 2007. Most estimations suggest that this trend is likely to continue (IRENA, 2014, NREL, 2015). Thus, power systems of most OECD countries are now facing a mature context, with very low demand growth and ageing power plants.

Coordination functions of liberalised power system are mostly based on a combination of markets. In particular, the day-ahead market is supposed to provide long-term signals for investments in order to ensure a correct level of installed capacity and a technology mix compatible with environmental goals. Additional environmental and climate policies

are generally added to cope with this second aspect of providing a relevant technology mix.

Regarding long-term investment signal, several market failures of the energy-only market are identified in the literature among which the most frequently cited are (i) the existence of explicit or implicit price caps that prevent energy prices from reaching the high values required to ensure capacity adequacy, (ii) risk aversion and imperfect information which can limit the willingness of investors to build peaking plants or low-carbon technologies, and (iii) the lumpiness of investment decisions which further complicates the reach of the theoretically long-term equilibrium. Today, debates on power systems particularly focus on enhancing the issues of capacity adequacy while allowing the development of LCTs including in particular RES-E, in relation to the environmental objectives (Finon and Roques, 2013).

This context raises key research topics to be investigated in this thesis. Firstly, the development of LCTs, including variable RES-E, is encouraged through specific environmental and climate policies for different reasons, among which mix diversification, energy independence and climate mitigation. As long-term market signals are not sufficient to trigger the development of these capital-intensive technologies, specific support mechanisms (Feed-In Tariffs (FITs), Feed-In Premiums (FIPs), green certificates) are generally implemented at the national level. However, these mechanisms can disrupt the market signals emanating from electricity markets by decreasing electricity prices ("merit-order" effect) and by adding uncertainty on the level of renewables that will emerge. Thus, some academics and political institutions call for a switch towards market-based instruments for the development of LCTs including variable RES-E (Hiroux and Saguan, 2010, Batlle et al., 2012, European Commission, 2015). But, this change of RES-E support schemes is in dispute among academics (Newbery, 2011, Fabra et al., 2014, Quirion, 2016). In this controversial context, the market-based development of LCTs should be analysed in details.

Secondly, the long-term capacity adequacy of liberalised power systems that should theoretically be ensured by the energy-only market still raises doubts and thus, capacity mechanisms are proposed to complement the energy-only market in its long-term coordination function (De Vries, 2007, Finon and Pignon, 2008, Cramton et al., 2013, Keppler, 2014). Besides, the increasing share of variable renewables further endangers

the capacity adequacy of power systems under energy transitions, by modifying the net electricity demand to be served by conventional technologies.

Finally, current power systems are usually organised around a combination of electricity markets and additional mechanisms designed for specific purposes as the development of LCTs including RES-E or capacity adequacy, in the context of energy transitions. This can suggest to consider alternative approaches to jointly tackle these two aspects instead of creating a specific mechanism for each goal. This idea of a common mechanism for both capacity adequacy and renewables development already exists in Brazil or Colombia where renewable technologies can compete with conventional ones in non-technology-specific auctions aiming at guaranteeing system adequacy in terms of capacity and energy[25]; even though some improvements remain to be done to provide full competition between these technologies (Mastropietro et al., 2014). Likewise, market-wide capacity forward auctions, to provide capacity adequacy and development of LCTs, are also discussed in the European context (Gottstein and Schwartz, 2010, Helm, 2010, Finon and Roques, 2013).

Thus, the analysis of the long-term coordination function of power markets, as detailed in this chapter, allows for the identification of two key challenges: triggering investments in LCTs, including in particular RES-E, and maintaining socially acceptable capacity adequacy in power markets facing energy transition. In order to analyse and propose policy insights to solve these two issues, a well-adapted modelling of investment decisions in liberalised power systems should be proposed. This is specifically the aim of following chapter II.

[25]In Brazil and Colombia, the generation adequacy problem concerns both capacity and energy. Indeed, these two electricity systems are characterised by a predominant share of large hydro power which explains that energy issues can occur in dry years.

Chapter II

Modelling investment decisions in electricity markets

* * *

Investments in electricity generation are central to the well functioning of power systems and are theoretically coordinated by long-term signals emanating from electricity markets (chapter I). In this respect, this second chapter presents how investment decisions can be modelled with the underlying objective of proposing an analytical framework for addressing the long-term issues of renewable investments (chapter III) and capacity adequacy (chapter IV).

Section II.1 gives an insight on the decision-making process with particular application to the power sector. Then, section II.2 discusses the different options to model the long-term evolution of power systems before selecting the approach of System Dynamics modelling as the analytical framework of this thesis. Section II.3 presents in details the Simulator of Investment Decisions in the Electricity Sector (SIDES) that has been entirely developed for the purpose of this doctoral thesis. Finally, section II.4 concludes on the long-term modelling of power systems.

Contents of chapter II

II.1 Investment decisions in a risky environment

In liberalised power systems, the electricity generation mix and its temporal evolution are explained by investment decisions of private investors which depend on the long-term price signal emanating from electricity markets and eventually additional policy drivers. In the following, the issue of investment is tackled from the standpoint of an individual private investor that decides to invest based on the comparison of estimated economic values of the different generating technologies. These estimated economic values are drawn from anticipations of revenues on hourly power markets during the lifetime of the power plant.

This section provides an analysis of the investment decision process. Firstly, the key elements and assumptions of economic evaluation are discussed for investment decisions. Secondly, risk aversion is given a special attention because of its prominent role in any liberalised economic sector.

II.1.1 The investment problem

In power systems, an investor is confronted to two major questions in which uncertainties play a fundamental role: (i) determining the level of capacity to be invested in and (ii) selecting the most profitable technological options for a given load profile to be served. The decision-maker's problem is also characterised by the lead time required to build the power plant, as well as the equipment's lifetime. To make its investment decisions, an investor should get its own representation of future drivers of the power system, regarding both demand-side and supply-side, in order to anticipate its market shares. When evaluating a given project, different cash flows are expected to occur each year along the lifetime of the project. The schedule of these cash flows directly influences the total value of the project in relation to the time preferences[1] of the private investor.

In the approach adopted here, the investment decision and the financing choice are distinguished. The investment decision consists in, first, evaluating the different investment project without financing considerations, and second, selecting the most profitable investment projects from the point of view of a private investor. The financing choice

[1]For an investor, it is completely different to have the expenditures first and then the revenues at the end of the project, or to have revenues first and expenditures then.

occurs once the best project has already been selected. The objective of the financing choice is to determine the best solution to finance the project, in other word selecting the best ratio between equity and debt. Our methodological choice is to only address the investment problem whereas financing issues are not considered.

To evaluate an investment project, an investor has to anticipate the future through one or several future scenarios. *Scenario planning* and *corporate foresight* constitute a pan of the economic literature which aims to explain how long-term anticipations of the future should be defined. Scenario planning[2] is defined by Schwartz (1991) as "a tool for ordering one's perceptions about alternative future environments in which one's decisions might be played out". A key element of scenarios planning is the definition of the time horizon which typically varies from three to twenty years (Bradfield et al., 2005), whereas longer time horizons can be employed by administrations or large companies that have sufficient enough human resources to carry out scenarios planning on a long-time perspective. Moreover, in power systems, most power plants have a long life time (more than 50 years for nuclear plants), which thus reinforces the need to anticipate the future on a long period. However, in practice, it is unlikely than private investors can anticipate the future on several decades with a low level of risk.

In practice, modelling private investment decisions should at least integrate the following key elements summarised by Botterud (2003): (i) a process coherent with the decentralised decisions in liberalised electricity systems, (ii) investment timing and construction delays, and (iii) long-term uncertainties. Various approaches to model elements (i) and (iii) are discussed in following subsections II.1.2 and II.1.3 while (ii) is addressed in section II.2.

II.1.2 Investment decision criteria of private agents

Investment decision criteria play a key role in investment decisions made by private agents. This subsection refers not only to the economic literature on this topic but also to interviews[3] with decisions makers in energy groups and financial banks on their investment decision criteria. These interviews conducted at the beginning of the thesis

[2]Scenario planning was first introduced in 1940 by RAND corporation but it really gains momentum in the 1970's (Chermack et al., 2001). Shell is known to be the first firm to define long-term future scenarios of oil prices in 1971. Shell decided to start building long-term scenarios after the statement in 1967 that the usual six-year ahead looking was not sufficient to anticipate the future.

[3]Eight persons from several energy groups and financial banks have been interviewed.

project are not sourced explicitly because of confidentiality conditions but they guide the understanding of private investment decisions presented here and rooted in the context of power sector.

II.1.2.a Discounting future cash flows for a private agent

When estimating the value of an investment, revenues and spendings occurring in different time-periods are to be compared. In practice, this is achieved by the use of a discount rate which reflects the ratio between earning one Euro today or one Euro the next year, in relation to the preference for the present. The introduction of a discount factor comes from the theory of inter-temporal choices and, in particular, the discounted utility model formalised in Samuelson (1937)[4].

The literature on the discount rate is divided into two major streams: (i) a first stream refers to public decisions and mainly focuses on intergenerational equity, and (ii) a second stream refers to private projects. As our methodological approach focuses on private agent, the following discussion concerns only the capital cost in the context of investment decisions made by private investors.

In private economic calculation, discount rate is often associated to the cost of capital even if the two concepts can differ. Pratt and Grabowski (2010) provide an insightful definition of the cost of capital: it is "the expected rate of return that the market participants require in order to attract funds to a particular investment". In that sense, the cost of capital is not defined by the firm in itself, but by market conditions observed by the firm. As detailed by Pratt and Grabowski (2010) and Helms et al. (2015), a distinction should be made between the cost of capital as defined above, which corresponds to a liability perspective, and the rate to be used to discount future cash flows from an investment perspective, which can integrate a hurdle premium.

The cost of capital is an expected and forward looking estimation of the cost of debt and equity of the firm based on market conditions. The most common approach to estimate the cost of capital is the Weighted Average Cost of Capital (WACC) which stipulates

[4]The formulation proposed by Samuelson extends previous works. Rae (1834) is the first to highlight the desire of accumulation and the preference for present consumption. Latter on, Bohm-Bawerk (1890), Fisher (1930), Pigou (1920) detail and formalise the natural underestimation of future incomes or future utility compared to present ones.

the following relation:

$$WACC = K_d \frac{D}{D+E} + K_e \frac{E}{D+E} \tag{II.1}$$

where D is the total debt of the firm, E is the equity of the firm, K_d is the cost of debt and K_e is the cost of equity. Here, the underlying assumption is that the firm is totally financed by his debt and equity. The cost of equity K_e is intrinsic to the firm and market conditions. It is commonly defined thanks to the Capital Asset Pricing Model (CAPM). If the cost of capital was to be used for investment valuation, it is noteworthy that K_d should corresponds to the cost of new debt and should not be defined accordingly to the debt already undertaken.

The CAPM was initially formalised by Sharpe (1964) and Lintner (1965), based on the the model of portfolio choice described by Markowitz (1959). In its model known as the mean-variance model, Harry Markowitz assumes a risk averse decision-taker who decides based on mean and variance. The works of Sharpe (1964) and Lintner (1965) add two more assumptions: (i) complete agreement on the distribution of future returns and (ii) borrowing and lending at risk-free rate (r_f).

In the CAPM, the cost of equity K_e is defined as:

$$K_e = r_f + \beta \pi_r \tag{II.2}$$

where r_f is the risk-free rate of the economy, β is a parameter of the firm and π_r is a risk premium of the considered activity. The risk premium is defined as the difference between the average rate of the market considered for the project and the risk free rate.

Since it was introduced in the 1960's, the CAPM has been widely employed by private investors to estimate their cost of equity. Usually, it also constitutes the method to define the discount factor to be used in private investment decisions. Indeed, Graham and Harvey (2001) finds that more that 70% of Chief Financial Officers (CFOs) use the CAPM to estimate their cost of equity, based on a review of 392 CFOs. However, the limits of this model have been highlighted since the early 1970's. Fama and French (2004) review several empirical studies on the use of CAPM and conclude that the Sharpe-Litner version of the CAPM is insufficient to estimate the cost of equity. In particular, they point out that "CAPM estimates of the cost of equity for high beta

stocks are to high (relative to historical average returns) and estimates for low beta stocks are too low".

In the economic literature, very few studies propose to estimate the WACC or the beta for the electricity sector. Buckland and Fraser (2001) estimate betas for electricity distributors (regulated business) in the United Kingdom, which appear to be time-varying, and highlight that beta values are generally over-estimated by investors. Other studies directly estimate the WACC. Back in the 1960's, Miller and Modigliani (1966) give an analysis of a sample of 63 separate firms of the American power sector for the years 1954, 1956 and 1957, and obtain an estimated cost of equity in the range of 5.1-6.2 % and then, an estimated average cost of capital in the range of 3.6-4.6%. More recently, Helms et al. (2015) propose a synthesis of WACC's estimations for three big power utilities in Germany from 2006 to 2013. The two authors show that the WACC varies between 6% and 10%. According to an estimation of Eurelectric (2013), the average WACC of European power companies is 8.2% in 2012, which is in the same range of the aforementioned estimations.

In the last edition of the *Projected Costs* (IEA and NEA, 2015), the International Energy Agency (IEA) indicates that its choice for the discount factor refers to private investments, estimated by the WACC. The study uses three different values: 3%, 7% and 10%, while the previous edition (IEA and NEA, 2010) considers 5% and 10%. This up-date discount factor is justified by a survey on cost of capital carried out in seven different countries (Germany, Korea, The Netherlands, New Zealand, Switzerland, the United Kingdom (UK) and the United States of America (USA)). Finally, the report (IEA and NEA, 2015) recommends to consider a discount factor of 3% for government-owned utilities in stable environment, 7% for private investors with low risk of default in a stable environment and 10% for private investors with high financial, technological and price risks.

Whatever the critics made by economists, the WACC remains a concrete estimation of the cost of capital based on financial and market conditions. However, firms are free to use their estimated WACC as the discount factor for investment evaluations or to defined this discount factor on other basis[5].

[5] A study by Graham and Harvey (2001) carried out for 392 CFOs indicates that CAPM is the most common techniques (used by 70% of them) followed by arithmetic average historical return (38%) and multibeta CAPM (33%).

Regarding the methodology developed here (see section II.3), the point of view adopted is the one of a private firm investing in power markets. Consequently, the discount rate defined in the SIDES model refers to the case of private investment valuation. When required, the discount rate used in the simulations is 8% (central assumption of DGEMP (2003) and DGEC (2008)) which is consistent with the above-cited estimations.

II.1.2.b Investment criteria

Investment decisions are generally based on quantitative indicators. Among them, an important distinction should be made between investment criteria guiding the decision-making process and the criteria required by the banks to support the project. The former criteria are detailed in the following section while the latter are not discussed in the scope of this dissertation.

Classical investment criteria can be classified into four main categories (Biezma and San Cristobal, 2006): (i) net present value methods, (ii) rate of return methods, (iii) ratio methods and (iv) payback methods. These different approaches are reviewed below with the aim of identifying their respective relevance.

In what follows, revenues occurring in year y are noted $Rev(y)$ and expenses $Exp(y)$. The initial investment cost is noted I and the discount factor r. The project is assumed to start in year $y_0 = 1$ and to last for N years.

Net Present Value

Both in the context of private and public investments, the Net Present Value (NPV) is the basic approach to assess the value of a project. The NPV corresponds to the economic balance between anticipated costs and revenues of the project with a time reference set to the decision date. The idea is to estimate costs and revenues for each year of the project's life-time and to value each Euro according to its date of occurrence. More concretely, the Net Present Value is the sum of discounted cash flows of the project with a certain discount factor to be defined accordingly to the firm's preferences. Classically, an investment is economically profitable if its NPV is positive and consequently, the "static NPV rule" indicates that a project should be undertaken if its NPV is positive, while a project with negative NPV should be rejected.

$$NPV = -I + \sum_{i=1}^{N} \frac{Rev(i) - Exp(i)}{(1+r)^i} \tag{II.3}$$

Considering that an investor has to choose between several investment projects with positive NPVs, it is classically admitted that the project with the highest NPV should be undertaken first. This is valid only under the assumption that the considered projects are independent from one another.

The "static NPV rule" is widely criticised in the economic literature[6] (Dixit and Pindyck, 1994, Ross, 1995). First, although the NPV is an indicator of the project magnitude, it does not estimate its economic performance. Indeed, supposing that two projects have the same NPV but very different initial investment costs, it is admitted that an investor would prefer the project with the lower investment cost for the same magnitude of NPV; but this is not reflected in the simple NPV approach. Then, an intuitive approach could be to look at the ratio between the NPV and the initial investment cost. This is known as profitability index which is detailed latter on. Second, the discount factor used to compute the NPV always remains a source of criticism even in the case of private decisions, as discussed in subsection II.1.2.a.

Internal Rate of Return

Another common investment criterion is the Internal Rate of Return (IRR), which corresponds to the discount factor that makes the NPV of the project equals to zero. The IRR indicates the maximum capital remuneration rate that is possible to apply while ensuring that the investment project remains economically profitable. Technically obtained by an iterative procedure, the IRR satisfies the following equation:

$$0 \approx -I + \sum_{i=1}^{N} \frac{Rev(i) - Exp(i)}{(1+IRR)^i} \tag{II.4}$$

Mathematically, the IRR is obtained by solving an equation. In most cases, the solution is unique and easy to compute thanks to software tools. However, some cases show

[6] Dixit and Pindyck (1994) make the following notable statement: "the simple NPV rule is not just wrong; it is often very wrong".

multiple solutions or even no solution, which can make it difficult to compare projects based on their respective IRRs.

An investment should be undertaken if its IRR is higher than a minimum required rate that is generally defined to the cost of capital of the firm (estimated by the WACC) plus an eventual risk premium. In corporate finance, this is often referred to as "the hurdle rate rule". To choose between several investment projects with IRRs higher than the required value, the investor should simply select the project with the highest IRR. Contrary to the NPV, this criterion – which is basically an economic performance indicator – does not create a bias between projects of different sizes.

Payback period

The payback period estimates the number of years required to recover the initial investment cost. It corresponds to the year-horizon that ensures that the sum of cash flows[7] between the starting year and the payback period exactly equals to the initial investment cost. If the payback period is noted N_{PP} (expressed in years), it is defined by the following equation:

$$I \approx \sum_{i=1}^{N_{PP}} Rev(i) - Exp(i) \tag{II.5}$$

The payback period gives an estimation of the time during which the project is not yet profitable. Indeed, the investment project will induce losses if abandoned before the payback period. This time indicator is not sufficient in itself: it does not allow for the comparison of several projects simply on this basis. First, it is a myopic (short foresight) approach and it does not provide any information on the project after the payback period. Consequently, it is not consistent with the objective of maximising the firm's value. Second, this criterion uses nominal values instead of discounted values and thus, it doesn't follow the general analysis of discounted cash flows. For this latter reason, some prefer to estimate a *present value-adjusted payback period* by discounting cash flows. Overall, it can be considered as an interesting complementary estimation

[7]Generally, the payback period is estimated without discounting cash flows but an alternative definition can use discounted cash flows.

for investors which can be used in practice to model a preference for shorter pay-back period, but not as the main decision criterion.

Profitability index

The Profitability Index (PI) is an economic performance indicator which is defined as the ratio between the NPV of the project and the investment cost[8] as detailed in equation II.6. This investment criterion belongs to the ratio methods of the classification exposed in Biezma and San Cristobal (2006).

$$PI = \frac{NPV}{I} \tag{II.6}$$

The PI can be interpreted as the amount of money which is earned for every Euro initially invested in the project. When using this approach, a project is considered as economically profitable, and so can be undertaken, if its PI is greater than zero.

This criterion can also be used to prioritise the projects by undertaking first the project with the highest PI. Contrary to the simple NPV, the profitability index is considered relevant to compare projects with different investment sizes. However, this criterion has the same drawbacks as the NPV: it does not address time management issues and the choice of the discount factor can be questioned.

Firms' practices

Some empirical surveys propose a view of real practices of firms, which can be useful to check if methodologies provided in economic and corporate textbooks are effectively applied in investment decision-making. Graham and Harvey (2001) synthesise a survey of 392 CFOs from different industries including manufacturing, transport, energy and financial. Their empirical work shows that IRR and NPV are the most common evaluation techniques, employed by more than 70% of interviewed CFOs. Hurdle rate and payback period come just after with roughly 55% of CFOs using these techniques.

[8] Alternatively, PI is sometimes defines as the discounted cash flows of the project excluding the investment cost (hence $NPV - I$) divided by the investment cost. In this case, a project is economically profitable if this alternative PI is greater than one.

Ten year later, Baker et al. (2011) confirm that NPV and IRR remain the most used valuation techniques.

However, while in the modelling it could be more convenient to use a single investment criterion, additional information can be obtained if several investment criteria are considered at the same time (Biezma and San Cristobal, 2006). In practice, firms are likely to decide based on a set of different investment criteria. Nevertheless, if a unique investment criterion has to be chosen for modelling purpose, it can be the NPV or IRR as suggested by the empirical surveys of Graham and Harvey (2001) and Baker et al. (2011).

In the model developed in the context of this research work (see section II.3), the investment decision is based on the PI derived from the NPV because it allows the comparison of technologies with different investment sizes as it is the case when choosing between nuclear power or combustion turbines.

II.1.2.c Using investment criteria in practice: an illustrative case

This section presents an illustrative case of an electricity generation project, which allows for a better understanding of the aforementioned decision criteria. The generation mix is supposed to consist of two different generating technologies: "Technology 1" which is used as a baseload technology and a "Technology 2" which has a higher variable cost than the first technology. Table II.1 summarises the assumptions on the two technologies. The energy price cap is supposed to be set at € 10,000/MWh by the regulator in accordance to consumers' preferences in the considered area.

	Technology 1	Technology 2
Investment cost (k€/MW)	800	600
O&M cost (k€/MW.year)	20	5
Variable fuel cost (€/MWh)	60	120
Nominal power capacity (MW)	500	150
Lifetime (years)	30	15

Table II.1: Cost and technical assumptions of the illustrative case

Given the existing generation mix (which we do not detail here) and the price cap fixed on the energy market, the electricity price equals € 10,000/MWh during 10 hours per

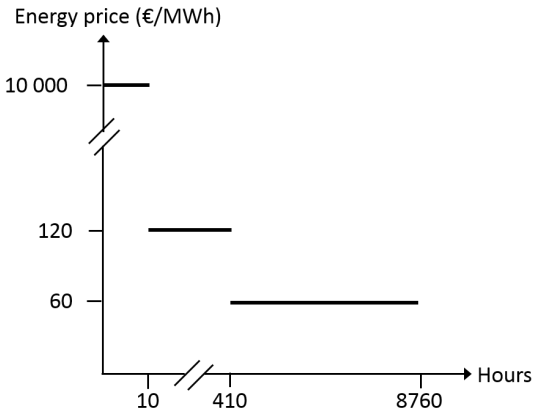


FIGURE II.1: Price load duration curve in the illustrative case.

year, € 120/MWh during 400 hours per year and € 60/MWh on the rest of the year, as illustrated in figure II.1.

Investment decision criteria for the two technologies

The two technologies can be compared based on the different economic criteria introduced in this section. Table II.2 presents the results for four different criteria: the NPV for a project of the typical nominal power, the NPV expressed in € per MW, the PI and finally the estimated IRR. The three first NPV-based criteria suggest to invest in technology 1 rather than in technology 2. On the contrary, the IRR indicates to invest in technology 2.

	Technology 1	Technology 2
NPV per project (M€)	**229**	40
NPV per MW (k€/MW)	**457**	267
PI	**0.57**	0.45
IRR (%)	14.6	**16.3**

TABLE II.2: Investment criteria obtained for the illustrative case

This illustrative case concretely shows that the choice of the economic criterion can significantly influence investments and in particular the technological choice. In practice, investment decisions are certainly based on various indicators. However, when modelling investment decisions, it is necessary to select a given criterion for seek of simplicity. Thus, one should keep in mind that this choice can influence the results, even if the long-term

generation mix could remain very similar with the different investment criteria (see appendix C on this topic).

Sensitivity to the main assumptions

The investment decision criteria obtained above for the two technologies depend on the main assumptions, including investment costs, O&M costs, variable generation costs which set hourly prices, lifetimes and the discount rate. Figure II.2 shows how a 10% change in the technologies' characteristics impacts the estimated NPV for the two considered technologies. It highlights than, for the two technologies, a change of 10% in investment cost or discount rate affects the NPV by more than 10%. In addition, the economic value of technology 2 appears as more sensitive to its lifetime than in the case of technology 1. This results from a lower lifetime for technology 2. Besides, the economic value of technology 1 is significantly sensitive to the variable cost of technology 2 which directly influences hourly electricity prices and thus the infra-marginal rent of technology 1.

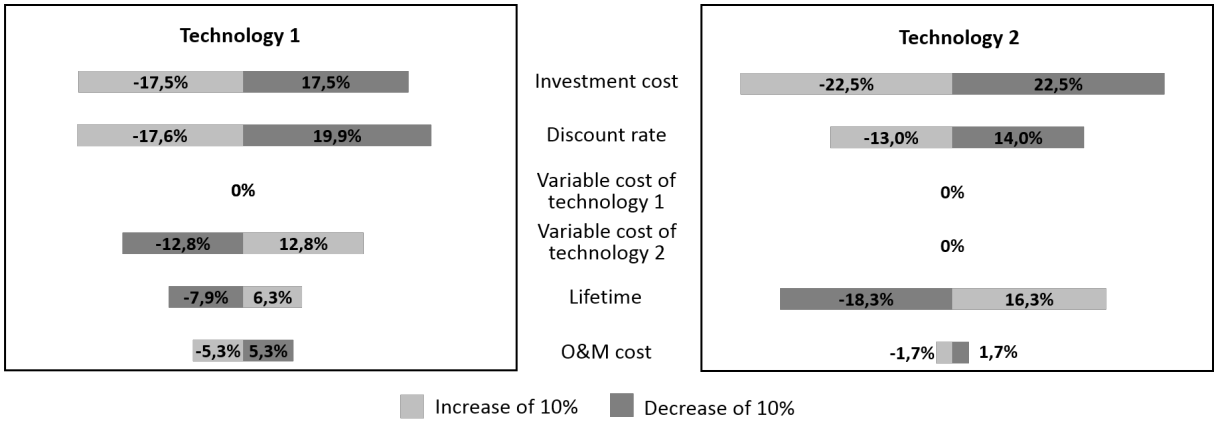


FIGURE II.2: Effect of 10% change on the NPV in the illustrative case.

Finally, in a risky environment, the economic value of an investment project can strongly depend on several assumptions among those illustrated here (investment cost, discount rate) but also the anticipated load profile. In this context, risk-averse investors can choose to introduce specific practises to manage risks and uncertainties related to their electricity generation project.

II.1.3 Risk aversion

In the power sector, electricity producers or consumers (or their electricity suppliers) can be risk-averse. This two kind of risk aversion can lead to very opposite effects: (i) risk aversion of electricity producers tends to reduce investments and thus, the installed capacity would be lower than in the risk-neutral case, whereas (ii) risk-averse electricity consumers would hedge against electricity shortages through higher installed capacity compared with the risk-neutral case. This dissertation focuses on modelling investment decisions of private investors in liberalised electricity markets. Thus, only risk aversion of electricity producers is discussed in the following. This section starts by discussing the different sources of risks and uncertainties in electricity generation. Then, it reviews the different approaches proposed by economists and decision makers to take risk into account.

II.1.3.a Where do risks and uncertainties come from in electricity generation projects?

When evaluating an investment project, the future outcome is unknown at the time of decision and so, there is automatically sources of risk or uncertainty. These two notions refer to the fact that there is a doubt or an ambiguity of the outcome of a future event. Originally introduced by Knight (1921), the distinction between risk and uncertainty is based on the possibility to estimate the distribution of future outcomes. The term "risk" is employed if the future outcome is unknown but its distribution can be measured or estimated ; while the term "uncertainty" refers to unknown future outcome characterised by an unknown distribution of outcomes. The following discussion focuses on risk rather than uncertainty, and presents the different tools for risk management in investment decisions.

Before dealing with the methods to integrate risk aversion in investment decisions, it is important to identify the largest sources of risk in electricity generation projects. Roques et al. (2006b) quantify the different risks for nuclear, Combined Cycle Gas Turbine (CCGT) and coal in the form of Tornado diagrams[9]. For these three technologies,

[9] A Tornado diagram presents the variation of the NPV expressed in percentage cause by a variation (in percentage) of the different sources of uncertainty.

	Description
Volume-risk	Risk related to the quantity of electricity generated and sold on the market, which strongly depends on the electricity demand of consumers. To a lesser extent, the volume-risk also depends on the availability of the generation units. This source of volume-risk can be hedged partially by taking technical measures to reduce forced and unplanned outages. For non dispatchable Renewable Energy Sources of Electricity (RES-E), the volume of electricity generated within a year is also significantly sensitive to weather conditions.
Price-risk	Risk related to the revenue from the electricity sold on the market, which depends on electricity prices. Generally, the further horizon on future electricity markets is three to six years. For example, on the European Energy Exchange (EEX), the longer maturity of power futures is six years.
Risk in costs	Risk related to investment cost, or to a lesser extent Operations and Maintenance (O&M) cost, which may significantly impact the NPV of a generating power plant. Depending on the technologies, fuel cost can also add risks to the project (for example for coal or CCGT).
Technical risks	Risks related to construction time, availability factor or load factor can be substantial sources of risk if not correctly managed. Compared to volume and price risks, a power company can hedge against technical risks through continuous improvements of its knowledge and expertise.

Table II.3: Different sources of risks identified in electricity generation projects.

they find that variations in electricity prices, construction time and availability factor significantly impact the value of the considered power plants.

Table II.3 details four major sources of risks that can exist in electricity generation projects. For our part, the case studies presented in chapters III and IV consider volume and price risks of electricity generation projects.

II.1.3.b How can risks be taken into account in investment modelling?

Classically, four main approaches can be used to model risk aversion: (i) utility functions, (ii) risk-adjusted discount factor, (iii) portfolio theory or mean-variance analysis and (iv) real options. Another classical approach to model decisions under risk is the stochastic dominance (Hadar and Russell, 1971, Whitmore and Findlay, 1978, Levy, 1992). Stochastic dominance is a risk-averse preference model based on different axioms. However, because of the use of multi-criteria, this approach can be too complex to be implemented in a computational model and for that reason, it is not widely used by decision makers and is not developed in the scope of this dissertation.

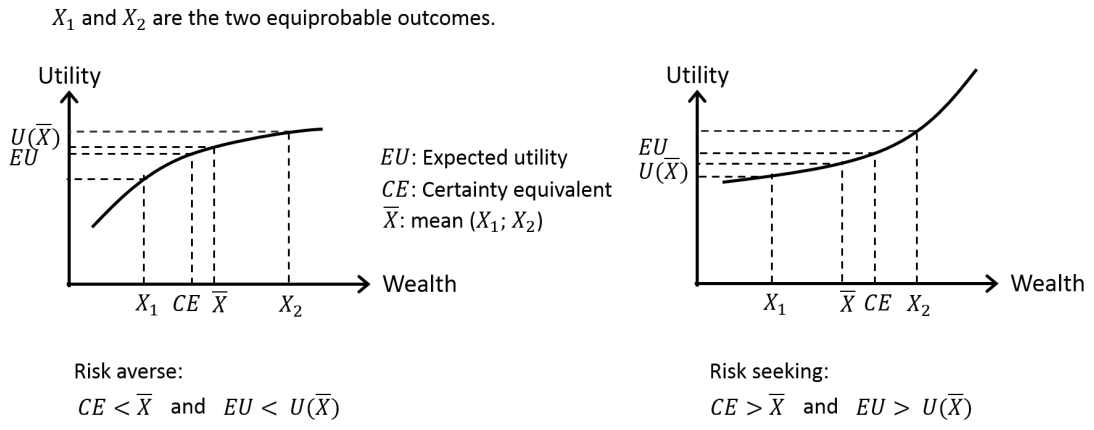


FIGURE II.3: Illustration of risk averse and risk seeking behaviours.

Utility function

Utility function is a tool introduced by economists to model preferences and in particular in risk related situations for which the reasoning on average gains can lead to different decisions than the ones observed in practice. This concept is central to the microeconomics theory according to which consumers are utility-maximisers. Historically, this idea of using utility functions to model risk related decisions was introduced in the famous *St. Petersburg paradox* or *St. Petersburg lottery*, stated in a private letter between Nicolas Bernoulli and Gabriel Cramer in 1713. This paradox is the beginning of an ample literature on individuals' preferences (Von Neumann and Morgenstern, 1947, Pratt, 1964, Arrow, 1971, Holt and Laury, 2002).

According to their preferences, investors may be risk-averse or risk-seeking, as illustrated in figure II.3. A risk-averse investor is represented by a concave utility function and is characterised by an expected utility lower than the utility of expected revenues (left graph in figure II.3). This means that a risk-averse individual would accept a certain payment of a value lower than the expected revenue rather than facing the uncertain event. Mathematically speaking, concave utility functions represent risk-averse preferences while convex utility functions correspond to risk-seeking preferences. Different utility functions are detailed in appendix B. In particular, two very classical concave utility functions employed to model risk aversion preferences are (1) Constant Absolute Risk Aversion (CARA) functions and (2) Constant Relative Risk Aversion (CRRA) functions.

In the utility theory of Von Neumann and Morgenstern (1947), the maximisation of expected profits is replaced by a maximisation of the expected utility or the certainty equivalent of the profits. The **certainty equivalent** is defined as the certain revenue that ensures the same utility as the expected utility of the distribution of the risky outcome. The difference between the certainty equivalent and the expected revenue corresponds to the so-called **risk premium**. Taking risk aversion into account through the use of certainty equivalent is recommended by economists (Aïd, 2014), but in practice, it appears that it is rarely applied by decision-makers.

Portfolio theory and mean-variance objective functions

The portfolio theory, also called the mean-variance analysis, proposes to overpass the economic evaluation of each project separately and to adopt a global and coherent management of all the assets of a firm. This approach was largely developed by Harry Markowitz during the 1950's.

The portfolio theory is based on a mean-variance analysis of assets. It specifies that expected gains are "a desirable thing", but that a high variance is "an undesirable thing" (Markowitz, 1952). Indeed, the higher the variance is, the more the investor is uncertain to get the expected gains; and the higher the expected revenue, the more economically interesting the project. A portfolio is considered as efficient if there is no other portfolio with the same mean but with a lower variance. To this end, the efficient frontier is plotted in a mean-variance graph as illustrated in figure II.4.

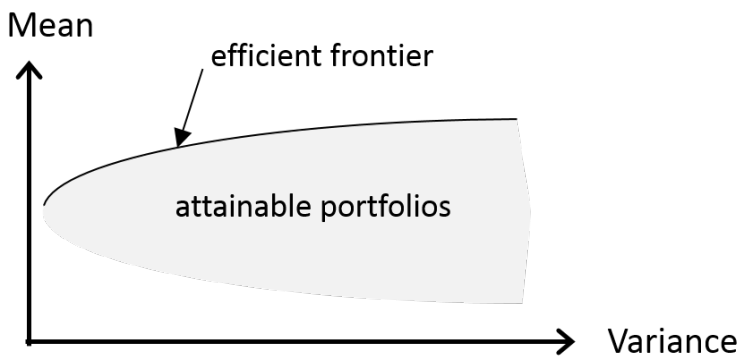


FIGURE II.4: Mean-variance graph for portfolio selection.

The demonstration of the equivalence between the portfolio theory and the direct utility maximisation has been widely focused on by economists and mathematicians, both from theoretical perspectives (Feldstein, 1969, Chipman, 1973) and empirical approaches in the context of historical or finite distribution of future outcomes (Levy and Markowitz, 1979) and in the context of infinite distribution (Kroll et al., 1984).

In order to get a simple application of portfolio theory and maximisation of expected utility, a common approach consists in maximising a mean-variance objective function (Levy and Markowitz, 1979). The mean-variance function (noted F) is generally defined as:

$$F(x) = \mu(x) - \frac{\alpha}{2}\sigma(x) \tag{II.7}$$

where x corresponds to the anticipated possible values of the project, μ its mean expected value, σ its variance and α represents risk-preferences of the considered investor. maximising this mean-variance objective function is equivalent to utility maximisation under certain assumptions on the utility function and on the distribution of the outcome (Chamberlain, 1983). In particular, if the utility function is supposed of the CARA-form and the variable x follows a normal distribution, the mathematical equivalence between maximising the expected utility or the mean-variance function defined in equation II.7 is trivial (see Appendix B).

The variance is a classical estimation of dispersion and is commonly used to quantify the risk of a distribution of outputs. Mathematically, it is well adapted for symmetrical distributions but it is largely criticised for non-symmetrical ones. Indeed, measuring risk forms a wide pan of operational research's literature. Among others, Ogryczak and Ruszczyński (1999) criticise the use of variance as a measure of risk in the portfolio selection proposed by Markowitz (1952) and they show that the use of semi-variance or semi-deviation allows for better results from mathematical perspectives.

Real options

Real options consist in a proactive risk management. The idea is to consider risk in a positive way admitting that risks can sometimes add value to a project. In that sense, the method consists in anticipating adaptive actions (flexibility) that can be undertaken in case a future scenario happens. To illustrate this approach, let us consider the example

of an oil well. A very simple real option for this project consists in adding a shut-off valve so that oil extraction can be stopped if oil price is below production costs. In a very simple manner, the presence of a shut-off valve adds a substantial value to the project by cancelling strictly negative net profits in case of low oil price. In practice, real options can vary according to their characteristics and their relations to the projects[10].

After Arrow and Fisher (1974) and Henry (1974a,b) highlighted real options in the real economy, the major conceptualisation of real option theory is proposed by Myers (1977) which criticises common valuation and states that "a significant part of many firms' market values is accounted for by assets not yet in place, i.e., by the present value of future growth opportunities". In the same trend, Trigeorgis (1993, 1996) argues that traditional NPV does not account for flexibility in project's management and thus, he supports the use of real options.

Despite its presence on economic and corporate textbooks, real options remain scarcely used in practice (Aïd, 2014). In the power sector, it seems that real options are quite unused in France and rarely used in the United Kingdom and Germany, while the concept is more popular in the oil and gas sectors. Baker et al. (2011) find that 81% of a set of 214 firms interviewed in their survey never use real options mainly because of a lack of expertise or knowledge on this approach.

Risk-adjusted discount factor

In decision making, a common way for firms to take risk into account is to incorporate a risk premium in the discount factor used to compute the NPV of the project (see section II.1.2.a). This approach is generally referred to as risk-adjusted discount factor. Even if this approach seems to be applied in practice, using risk-adjusted discount factor is not recommended by economists mainly because it confuses times preferences and risk preferences which are different concepts (Aïd, 2014).

Similarly, the question of adding a risk premium in the discount factor is also discussed in the context of public investment. More specifically, there is a controversy to determine

[10]Traditionally, there are two types of real options: (i) a *put* corresponds to a flexible action to be undertaken in order to minimise losses in case of averse future scenarios and (ii) a *call* is a flexible action to be undertaken in order to increase gains in case of favourable future scenarios. Besides, real options also varies in their relations to the project. An option *in the project* refers to a physical or technical action while an option *on the project* refers to a financial option.

whether risk should be taken into account in the discount rate is the same way in public decisions as in private ones. In the case of perfect markets, public agencies should theoretically decide based on expected values without considering risk aversion (Arrow and Lind, 1970). However, the question of taking risk aversion into account in public decision is legitimate as soon as markets are not perfect. Given that risk-bearing cost is insignificant if the risk is borne by the government, Arrow and Lind (1970) support that the evaluation of public investments should ignore uncertainty and thus, the discount rate should not be motivated by considerations of risk borne by the public agency. By contrast, if the project entails specific risks borne by private individuals, the discount rate used in the public evaluation of the project should reflect risk preferences of these individuals.

* * *

If there seems to be an an overall agreement on the existence of risk aversion in the case of private investments in the electricity sector (Aïd, 2014), it is very challenging to propose an estimation of the risk aversion level. Such estimation can be carried out either by econometric analysis on markets' or firms' data, or by laboratory experiments, but generally, both methods are time and context-specific. To our knowledge of the literature, Litzenberger and Rao (1971) are among the very few to propose an empirical estimation of risk aversion in the electricity sector. Referring to the 1960's and based on a sample of eighty-seven electric utilities, they show that investors are risk averse and estimate their marginal required return.

However, the lack of empirical estimation of the level of risk aversion in the electricity sector does not impede to propose long-term electricity models that take into account risk aversion. In practice, the four approaches detailed above have been used to model the electricity sector: (i) concave utility functions, (ii) risk-adjusted discount factor, (iii) portfolio theory or mean-variance analysis and (iv) real options.

II.2 Long-term modelling of power markets and generation mix

This section proposes an overview of the different methods to analyse and model the electricity generation mix and its temporal evolution. Since the liberalisation of the electricity market, many models have been proposed to get a better understanding of the functioning of power markets. Among the rich literature on electricity modelling, it is difficult to propose a unique and uniform taxonomy of the different approaches used to study the electricity generation mix. Indeed, the frontier between each method may be unclear and based on its background, everyone gets its own mental picture of the different approaches. Consequently, the following presentation and discussion about the methods to study this specific topic does not intend to be neither comprehensive, nor the unique taxonomy.

To analyse investment decisions in detail, the Levelised Cost Of Electricity (LCOE) is a limited tool as shown in section II.2.1. Thus, more complex models are required. The analyse of the various modelling approaches presented in this section is structured around three modelling families as proposed by Ventosa et al. (2005): optimisation models discussed in subsection II.2.2, equilibrium models discussed in subsection II.2.3 and simulation models discussed in subsection II.2.4. Then, subsection II.2.5 compares these various modelling approaches.

II.2.1 Comparison of levelised costs of generating technologies

The LCOE of a technology χ refers to the average cost of producing a MWh taking into account its annualised investment cost (AIC_χ), annual O&M cost (OC_χ) and the sum of variable generation costs ($VC_\chi(y)$) over the period which may include the carbon cost resulting from the carbon pricing. It corresponds to the ratio between total expected costs and total expected electricity outputs ($EP_\chi(y)$). All quantities are expressed in present value equivalent with a discount rate (r). Equation II.8 corresponds to the classical way of computing LCOE on the lifetime of the power plant. Eventually, the LCOE can also take into account the decommissioning cost that occurs at the end of the lifetime of the power plant. This would be particularly relevant for nuclear plants.

$$LCOE_\chi = \frac{\sum_y \Big(OC_\chi(y) + AIC_\chi(y) + VC_\chi(y)\Big)(1+r)^{-y}}{\sum_y EP_\chi(y)(1+r)^{-y}} \tag{II.8}$$

Usually, to simplify the representation of the LCOE, the annual O&M cost and (OC_χ), the annualised investment cost (AIC_χ), the variable generation cost (VC_χ) and the annual total electricity generated by the power plant ($EP_\chi(y)$) are supposed to be constant over time. In this case, the expression of the LCOE can be simplified into equation II.9.

$$LCOE_\chi = VC_\chi + \frac{OC_\chi + FC_\chi}{EP_\chi(y)} \tag{II.9}$$

The LCOE can also be interpreted as the constant hourly electricity price that is required to set the Net Present Value (NPV) of the power plant to zero, provided that the considered plant is perfectly dispatchable, or in other words able to produce at any time to its full power capacity. In this regard, LCOE is widely employed to assess the respective cost-prices of electricity for each generating technology, and to determine the most economic technology at the margin of the system. However, comparison of LCOE with hypotheses on load factors is relevant if conducted for a same group of technologies. This comparison would be valid if we could suppose that the value of a MWh is the same at any hour of the year on the electricity market which is generally not the case, or if the technologies are perfectly dispatchable and have a similar generation profile (Joskow, 2011). Thus, a comparison of technologies based on LCOEs can be misleading (in particular for non-dispatchable technologies) if conducted in any power system with conventional plants, except if the system has very flexible resources as dispatchable hydro-power or if the electricity demand has a high price-elasticity.

To go further in the comparison between conventional dispatchable technologies and variable Renewable Energy Sources of Electricity (RES-E), one relevant approach consists in estimating the so-called system costs which are defined as "the total costs above plant-level costs to supply electricity at a given load and given level of security" (NEA, 2012). These system costs can include (i) grid costs related to the plant as for example the costs associated to grid extension, grid reinforcement or also balancing services, and (ii) other external costs related to the plant which are usually harder to estimate, as for example environmental impacts (if not already internalised in power markets).

Likewise, Ueckerdt et al. (2013) and Hirth et al. (2016) propose to overcome the limits of the classical LCOEs by introducing what they called *System LCOE* which corresponds to the classical LCOE corrected by an additive factor (either positive or negative) that corresponds to the costs of transforming the electricity generated by the considered technology into a reference electricity good. Their approach is based on the recognition of three dimensions of heterogeneity (time, space and lead-time between contract and delivery) that make the product electricity different from a technology to another, as already discussed in section I.1.1 of the first chapter. More specifically, Hirth et al. (2016) define the cost of transforming the electricity good to the reference one as the difference between the demand-weighted average of instantaneous marginal values of electricity[11] on the one hand, and the specific technology's profile-weighted instantaneous marginal value of electricity on the other hand. This can also be interpreted as the integration cost of the technology. Finally, the system LCOE allows for a shift from the cost paradigm of the classical LCOE which could be meaningful in the social planner's perspective, towards the value of the generated electricity on market powers which is more fitted to liberalised systems.

In practice, investments in power markets come from private firms: their decisions are based on the assessment of economic values of the various technologies, rather than on cost-wide approach. Moreover, as pointed out in section II.1.3, private investors may be risk-averse. Consequently, if LCOEs can be used "to indicate ballpark differences between technologies" (Gross et al., 2007), this approach should not be used to draw business conclusions such as the value of a technology for private investors (Awerbuch et al., 1996). Similarly, LCOE can also be misleading for regulators as they should take into account the respective economic values of the generating technologies in their analysis of power systems. In liberalised electricity systems, policy makers should not satisfy with the sole cost-wide LCOE approach but should develop models to estimate market values of the different technologies in order to consider the reality of economic investment decisions taken by decentralised agents (Gross et al., 2010).

[11] The instantaneous marginal value of electricity corresponds to the value that consumers are willing to pay to consume an additional MWh of electricity on a given hour.

II.2.2 Optimisation models

The problem of investments in electricity generation is commonly studied from the point of view of optimisation. This methodology is largely inherited from former utility monopolies which aimed at serving the electricity demand at least cost. Today, this approach is still applied to study long-term issues of liberalised energy markets, under the assumption of perfect competition. This section focuses on long-term optimisation models[12] because they include investment decisions as decision variables of the problem.

II.2.2.a Social welfare maximisation, cost minimisation and profit maximisation

In optimisation approaches, the problem can be formalised as a least cost objective function or maximum profit one, subject to a set of technical and economic constraints.

Cost minimisation aims at defining the generation mix (and the short-term use of the different power plants) to serve the electricity demand at least cost. Classically, the objective function is the total cost to serve the demand, including investment costs. The cost of electricity outages can also be part of the objective function. The constraints of the optimisation problem represent the obligation to serve the demand, the operational constraints of the different generating technologies, and, eventually, grid and interconnection constraints. This approach initially fits the process of a social benevolent planner and then, by extension, it corresponds to liberalised power markets under assumptions of perfect competition.

Profit maximisation aims at defining the generation mix resulting from the decisions of individual firms which maximise their profits. Therefore, the objective function corresponds to the total profit earned by one or several individuals firms. As in the previous approach, the constraints of the profit maximisation problem refer to the functioning of electricity markets. The profit maximisation is inherent to liberalised power markets with private investors taking their decisions individually. From a mathematical perspective, the profit maximisation problem can be interpreted as the dual problem of the cost maximisation one.

[12] Another family of optimisation models, the so-called "dispatch models" or "unit commitment models", focuses on the short-term uses of existing generation units to serve the electricity demand at least cost. In this case, investments are not part of the problem.

According to the economic theory, the first objective of the social planner (or the regulator) is to maximise the social welfare. Historically, state-owned monopolies acting as social planners[13] applied this principle through the cost minimisation subject to the constraint of serving the electricity demand often considered as inelastic. However, in liberalised power sectors, investments in generation capacities (and Demand-Response (DR) programs) are on the behalf of private investors who intend to maximise their individual profits.

In the microeconomics theory, private profit maximisation leads to social welfare maximisation under pure competition and perfect information. Caramanis (1982) argues that this applies to power systems:

> "Derivation of social welfare maximising investment conditions shows that they coincide with individual profit-maximisation investment behaviour. Thus if individual generating units and electricity consumers were to operate as independent profit-maximising firms and make investment decisions independently, profit maximisation would be sufficient to induce them to adopt precisely the socially efficient investment decisions."

This statement is valid under certain assumptions among which the most important are: (i) perfect competition and perfect spot pricing, (ii) perfect information available to all agents, and (iii) equality between the social discount rate and the individual discount rate used by private investors.

However, these three assumptions are questioned in the complex context of power systems (see section II.1), in particular concerning perfect information and discount rate (or cost of capital).

II.2.2.b Optimisation models used in practice

Concerning the study of the power sector, optimisation models can be distinguished among at least two characteristics (Ventosa et al., 2005): exogenous or endogenous

[13] Here, the monopoly is subject to a regulation from the government so that the monopoly acts as a social welfare maximiser. On the contrary, unregulated monopolies' decisions are unlikely to lead to social welfare maximisation.

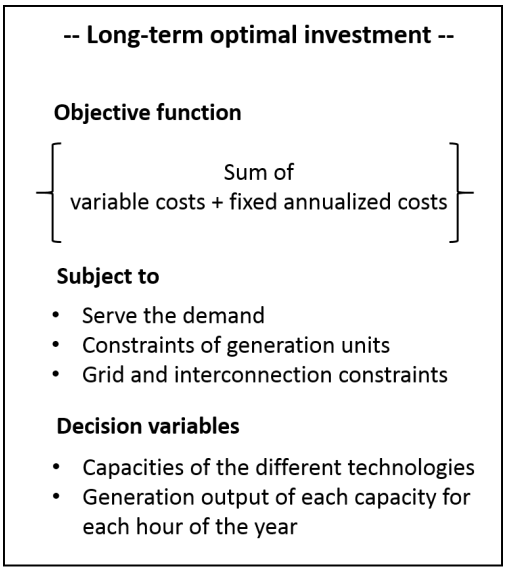


FIGURE II.5: Illustration of the principle of long-term optimisation solved in one step.

electricity price, and deterministic or stochastic properties[14]. The representation of risks in optimisation models has originally been developed by Dantzig (1955) in the context of linear programming and then, it has been applied to power systems, in particular by Murphy et al. (1982) and Modiano (1987) concerning the effect of uncertain demand.

A large variety of optimisation models applied to power system can be found in the literature. Some articles provide a survey of such models. In particular, Hobbs (1995) proposes an interesting survey of optimisation models with special attention to the way transmission issues, risks and imperfect competition can be taken into account. Besides, the review of Kagiannas et al. (2004) emphasises the lack of optimisation models that include capacity investments and operation issues in an oligopolistic context. A more recent survey of stochastic optimising models for investment decisions and long-term system optimisation can be found in Möst and Keles (2010).

Concerning the practical implementation, long-term optimisation models (*capacity planning*) can proceed either in one optimisation of the global problem (figure II.5) or either by decomposing the short-term dispatch and the investment module (figure II.6). In both cases, the optimal installed capacities are obtained as an output of the simulations.

[14]By saying stochastic and deterministic, Ventosa et al. (2005) refer to the possibility of taking risks or uncertainties into account in the model. However, the precise meaning of deterministic versus stochastic does not lies in the possibility to add risks, but rather in the way the risks or uncertainties are represented in the model.

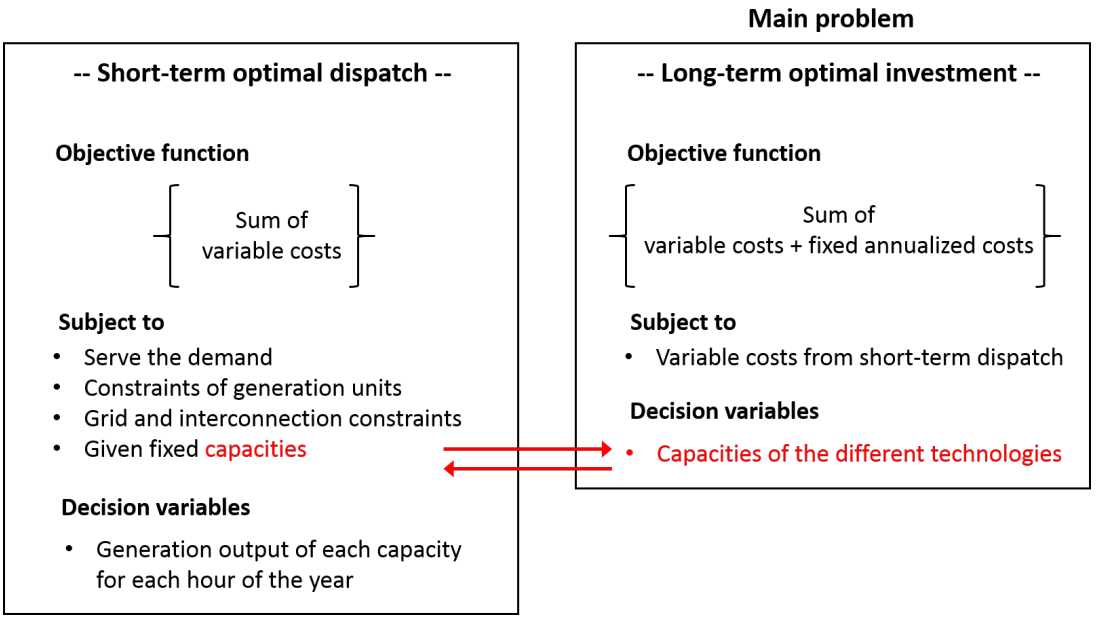


FIGURE II.6: Illustration of the principle of long-term optimisation solved by a decomposition between short-term dispatch and long-term investment.

Optimisation models can differ on their time horizon but more significantly, they can also differ on the study period. A first option is to solve the optimal-mix problem for a specific year defined on a given time horizon using annualised investment costs. A second option is to consider an inter-temporal optimisation resulting in the evolution of the generation mix on several years, given a perfectly anticipated evolution scenario of the electricity demand. An other option is to consider the optimisation on several years but with dynamic anticipation of the future. This difference in the goal of the model induces different practical solving algorithms.

The so-called "static" optimisation of the generation mix defines the optimal generation mix to serve the demand on a given year. In this case, if no existing generation is assumed as inputs of the model – as it is commonly the case – the resulting optimal generation mix can be characterised as "build from scratch" or "green field".

Static optimisation of the generation mix

The *screening curves* method is a classical and common approach to define an optimal mix for a given load duration curve (static optimisation), under some simplifications on the functioning of the power plants (Stoft, 2002, Green, 2006). The approach is described in previous section I.1.2 of chapter I.

This approach suffers from several limitations. First, the functioning of power units is simplified by not taking into account dynamic constraints. In practice, power units must respect several operational constraints (see section I.1.2) and consequently, their flexibility is not perfect as the assumption made in this approach. In particular, hydropower and pump and storage are difficult to integrate in the screening curves approach. Second, this approach defines a mix "build from scratch" or in other words "green field" without taking into account an inherited existing mix. However, it could cope with a context of a large growth of the annual load addressed to conventional technologies. But in a context of decreasing residual demand (net from electricity generated by undispatchable RES-E) due to entries of renewables by out-of-market support mechanisms, this limitation becomes crucial.

Nevertheless, the *screening curves* approach remains a commonly used method because of its strong graphical illustration. In particular, it has been employed to study the long-term effects of introducing exogenous RES-E by using a net load duration curve (net from electricity generated by RES-E). For examples of studies with the *screening curves* approach, see Stoughton et al. (1980), Grubb (1991), Green (2005), Kennedy (2005), NEA (2012) and Keppler and Cometto (2013).

Besides, some propose to expand this traditional screening curves approach to take into account additional elements as the short-term operational characters of the different technologies (Batlle and Rodilla, 2013).

The static optimisation of the generation mix can also detail more specifically the functioning of the generation units by adding (forced or planned) outages or dynamic constraints of the power plants. The problem can be formulated as a cost minimisation or a social welfare maximisation or a profit maximisation.

In this approach, the optimisation problem cannot be solved by a graphical method as it is the case for the *screening curves* approach. Depending on the considered operational constraints of the power plants and depending on the representation of their capacity size as continuous or discrete variables, the problem can be solved by linear programming or mixed integer linear programming. Examples of static optimisation models can be found in Bushnell (2010), Green and Vasilakos (2011a), De Jonghe et al. (2012) and Green and Léautier (2015).

Finally, static optimisation models can take into account a number of constraints that represent the functioning of power systems, but the limits regarding the static view already mentioned for the *screening curves* approach remain valid.

Optimisation of the generation mix on several years

Other optimisation models – generally refer to as *generation expansion models*– consider the evolution of the generation mix over several decades. In such models, the decision variables are of three kinds: expansion sizes, expansion times and capacity types (Luss, 1982), whereas the aforementioned static optimisation models consider only the sizes and the capacity types within a static problem. Generation expansion models can differ on their representation of the future path. Some models solve the problem under perfect foresight (Nagl et al., 2011), while others consider an optimisation with a representation of the risks that does exist on the future evolution of the system (Ahmed et al., 2003, Fuss et al., 2008).

There are different approaches to take risks or uncertainties into account in optimisation models, which can induce significant differences in their practicability, types of required data and computational times. Among others, stochastic programming, fuzzy programming and stochastic dynamic programming are common approaches to consider risks in optimisation models (Sahinidis, 2004). More specifically, single-stage stochastic models represent uncertain parameters by their average value and standard deviation weighted with a risk aversion coefficient. Multi-stage dynamic stochastic models can consider a more detailed representation of risks, but this approach can also raise computational problems. Generally, these multi-stage stochastic models represent the future by a multi-layered tree of future events, with associated probabilities for each branch as illustrated in figure II.7. This type of models allows to determine the optimal evolution of the generation mix on a number of years, within an simulation context that takes risks into account. Usually, the problem is solved thanks to the use of dynamic programming with backward induction (Bellman and Dreyfus, 1962), from the last leave of each branch to the initial node, by determining the best solution at each step.

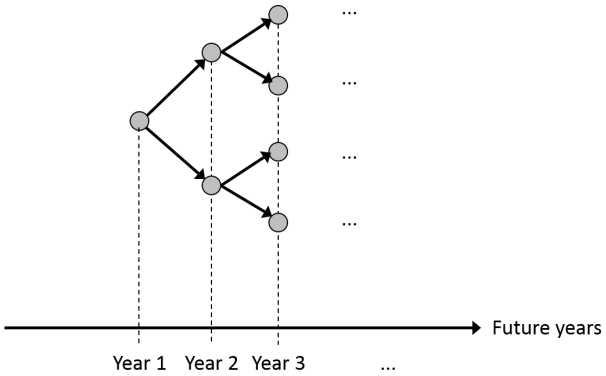


FIGURE II.7: Representation of future scenarios by a tree.

* * *

Optimisation models have been extensively used to study power systems. Various optimisation approaches exist spanning from static models to dynamic optimisation under uncertainties. Concerning the topic of this dissertation, effects of variable RES-E and in particular wind power have been analysed thanks to optimisation models (Nagl et al., 2011, Fürsch et al., 2014, Green and Léautier, 2015). However, such models are generally used to focus on system effects while considering the RES-E development as an exogenous constraint, rather than estimating potential endogenous RES-E investments. Besides, regarding capacity adequacy issues, optimisation models expressed as cost minimisation consider the constraint of serving electricity demand and thus, it can not provide insights on the level of installed capacity that would emerge with different market architectures.

II.2.3 Microeconomic equilibrium models

To simulate the mix resulting from the firms' decisions in liberalised power systems, computable equilibrium models' family includes every approach based on an explicit representation of market equilibria within a traditional mathematical programming framework (Ventosa et al., 2005). Among this family, a common distinction is generally made between microeconomic models which focus on agents' behaviours, and macroeconomic models which focus on the global functioning of the economy. These two types of equilibrium models differ at least on two relevant points: (i) microeconomic equilibrium models belong to bottom-up approaches as well as optimisation models and simulation models, whereas macroeconomic equilibrium models belong to top-down approaches,

and (ii) macroeconomic models aim at representing the overall economy and thus, the functioning of power systems is generally very simplified. Thereby, macroeconomic models are out of the scope of this dissertation because our research topic, which focuses on investments in power markets, requires an explicit representation of markets, behaviours and technologies. Thereby, only microeconomic equilibrium models are discussed in this subsection.

Microeconomic equilibrium models formalise the concepts of microeconomic theory in a mathematical framework that can be solved numerically. This approach allows to move away from the context of pure competition and perfect information. Generally, microeconomic equilibrium approach consists in two main steps: (i) modelling of individual behaviours of suppliers with different options of competitive environment and (ii) solving the problem to determine Nash equilibriums[15]. Whereas a distinction could be made between cost-minimising or profit maximising optimisation models, microeconomic equilibrium models are mostly based on profit maximisation of individual economic agents and thus, in that sense, it matches the functioning of liberalised electricity systems.

In practice, microeconomic equilibrium models enable to explore imperfect competition under the assumption of an oligopoly. In particular, common models are *Cournot model* where agents compete on quantities; *Bertrand model* where agents compete on prices and *Stackelberg model* where there is a leader agent and a number of followers. Concerning the comparison of these types of microeconomic models, Keane et al. (2013) suggest that the differences between Cournot competition and Stackelberg competition remain limited, based on a case study with two different microeconomic equilibrium models applied to the electricity sector. An other classical approach is the *supply function equilibrium* in which market participants are characterised by their supply function in quantity and price. This latter approach offers greater possibilities because it corresponds to a competition in both price and quantity, whereas Cournot competition supposes a competition on quantity only (Kahn, 1998). The literature on microeconomic equilibrium approach highlights that perfect competition and Cournot competition provide two extreme boundaries: other types of imperfect competition give results in between (see Klemperer and Meyer (1989) and Vives (2011) in the context of non-specific equilibrium models, and Bushnell et al. (2008) regarding power markets).

[15] A Nash equilibrium is a stable situation in which each agent uses its best strategy in response to the strategies chosen by its competitors

Concerning power markets, the theoretical framework of pure competition and perfect information is largely questioned. More specifically, strategic withholding of available capacities and market power are among the most cited elements to state that electricity markets are not perfectly competitive (Smeers, 1997).

Insights on strategic behaviours in power markets

Microeconomic equilibrium models are commonly employed to investigate strategic behaviours in liberalised electricity markets with two practical focuses: (i) short-run bid strategies on the different electricity markets and in particular on the day-ahead spot market, or (ii) long-term effects of strategic behaviours on the level of installed capacities. While perfect competition models (generally optimisation problems) can only provide ex-post insights on the real functioning of imperfect electricity markets, strategic behaviours models can propose ex-ante analysis of the electricity sector by describing the competition structure in a more realistic way (Smeers, 1997).

Reviews of the different uses of microeconomic equilibrium models to analyse imperfect competition in electricity systems are provided by Smeers (1997), Hobbs et al. (2001), Day et al. (2002) and Ventosa et al. (2005). Focusing on both power and gas markets, Smeers (1997) highlights that single-stage or two-stage equilibrium models provide relevant information and allow for ex-post analysis of electricity markets, but multi-stage equilibrium models remain much more complex and raise computational issues.

Concerning strategic competition for long-term investments, Meunier (2010) analyses how sub-investment can arise in a situation with heterogeneous firms (in terms of restricted access to certain technologies) making strategic investment choices of generating capacity, suggesting than sub-investment can also be explained by the competition conditions in addition to the other reasons cited in the literature, namely missing money for peaking units, risk management and exercise of market power. Based on the formalisation of three different equilibrium models with investments in generating capacities, Murphy and Smeers (2005) show that there is less exercise of market power if investments are based on energy remuneration from a spot market (but in this case, the game may lead to no equilibrium or a unique equilibrium depending on the case) than if generating projects benefit from power purchase agreements. On the same research topic, Grimm and Zoettl (2013) demonstrate that, contrary to common intuition, competitive

spot markets and investment incentives are inversely related under the assumption of strategic competition between firms for their investments in generating capacities.

Analysing RES-E development and capacity adequacy issues with microeconomic equilibrium models

Concerning the two research questions addressed in this dissertation, microeconomic equilibrium models have been used by Milstein and Tishler (2011) and Concettini et al. (2014) to analyse RES-E development and effects on the system, and by Creti and Fabra (2007), Ehrenmann and Smeers (2008), Fabra et al. (2011) and Lambin and Léautier (2016) to study capacity adequacy issues.

On these topics, microeconomic equilibrium models can provide relevant information on the long-term equilibrium arising from different competition strategies. However, this approach does not intend to provide insights on the transition phase to the long-term equilibrium.

II.2.4 Simulation modelling by Agent-Based and System Dynamics approaches

Simulation models are another modelling family. The basic idea of simulation models is to explicitly express a set of rules (or equations) that represent behaviours of investors and then, to simulate these rules for a number of time steps. Despite their emergence during the 1960's, simulation models have been employed to study liberalised power systems mainly since the 1990's. This approach appears to be particularly adapted to help the understanding of the functioning of liberalised markets characterised by new market risks and regulatory uncertainty, as pointed out by Larsen and Bunn (1999):

> "In seeking to address the issues of corporate, market and regulatory risk in a recently deregulated market, it seems that a simulation method which has its original source in system dynamics provides a balance of behavioural, dynamic and prototypical state representation which is conducive to creating new insights of the sort which more classical economic optimisation based models could not achieve."

Simulation models can have two main alternative objectives: (i) helping to predicting future evolutions or (ii) understanding specific issues of complex systems (Larsen and Bunn, 1999). Besides, because of the lack of experience with liberalised electricity markets, simulation models have been seen as a good option to get more insights on the long-term functioning of power systems and thus, helping policy design (Larsen and Bunn, 1999, Olsina et al., 2006). Here, the focus is given to the understanding of specific issues, in particular market-based investments in renewables and capacity adequacy in the context of energy transition, while predicting possible future evolutions is out of the scope of this project. Finally, compared to optimisation models or equilibrium models, simulation models provide a more precise description of behaviours and a more explanatory approach by allowing to test different values and options, rather than looking for the (optimal) solution (Ku, 1995).

II.2.4.a Simulation models used in practice

Two main types of simulation models can be identified from the literature (Teufel et al., 2013): (i) agent-based modelling which focuses on representing behaviours of economic players and (ii) System Dynamics modelling which focuses on temporal and structural interdependencies.

Agent-based simulation

Agent-based simulation provides a dynamics framework to model autonomous agents acting in response to their environment. Since 1990's, this methodology has received growing attention and application, including in the field of economics (Holland and Miller, 1991, Day and Chen, 1993, Arthur et al., 1997, Tesfatsion, 2002). Indeed, agent-based models provide interesting insights to study liberalised markets under a variety of assumptions including imperfect competition or imperfect information.

Generally, the structure of an agent-based model is made up of three main elements as detailed by Macal and North (2010): (i) a number of representative agents (typically, generators, suppliers and system operator) characterised by their attributes and behaviours, (ii) a number of agent relationships or interactions, and (iii) the agents' environment.

Once the different elements are expressed in detail, the agent-based modeller defines the initial state of the modelled economy or system and then, runs the process for several time-steps so that the evolution and eventually the equilibrium situation can be observed (Tesfatsion, 2002).

Compared to other simulation models as discrete event simulation or system dynamics, agent-based simulation allows for taking into account "the heterogeneity of agents across a population and the emergence of self-organization" (Macal and North, 2010).

Concerning power systems, agent-based simulation has been used to study a broad range of issues, among which market structures of consumers' behaviours, decisions and learning, market power and market design. Different agent-based models are reviewed by Sensfuß et al. (2007) and by Weidlich and Veit (2008) who propose a comparison of the results of different learning strategies for wholesale electricity markets. Bower and Bunn (1999) and Bunn and Oliveira (2001) are one of the pioneers to propose an agent-based model for electricity markets, applied to England and Wales.

In recent years, agent-based models have tended to be smaller and focused on specific issues. Indeed, while the outputs of big agent-based models can be challenging to interpret, new insights can be obtained by comparing outputs of smaller agent-based models to traditional industrial economy models. Nevertheless, a recurrent question discussed for agent-based models is whether the resulting Nash equilibrium is multiple or unique (Krause et al., 2006). Another criticism formulated against agent-based modelling is that despite the complexity of learning strategies, the representation of investment behaviours could remain too restrictive and too simplified compared to real behaviours suggesting that relevant models should be validated and robust against different strategies (Newbery, 2012).

System Dynamics

System Dynamics (SD) modelling is an approach that was developed with the idea to analyse non-linear relationships in complex systems over time. Created during the 1960's, this methodology is attributed to Jay Forrester (Forrester, 1961), Professor of the Massachusetts Institute of Technology (USA).

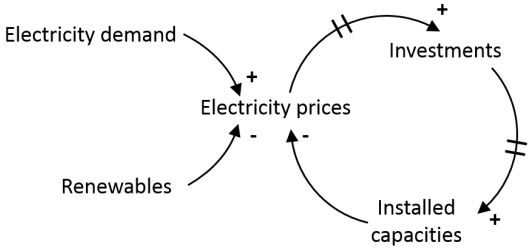


FIGURE II.8: Example of a simplified causal-loop diagram of power systems

SD modelling represents a complex system by identifying the boundaries of the systems, the different entities which belong to the system and more interestingly, the relationships between these identified entities[16]. Generally, the so-called causal-loop diagram illustrates SD models. Causal relationships between two system variables are indicated by arrows and the + (respectively −) symbol specifies positively (respectively negatively) related effect. A curved arrow indicates a feedback loop: either a negative feedback loop (represented by the − sign) which is is self-correcting, or a positive feedback loop (represented by the + sign) which is self reinforcing. A double slash represents a delay between the evolution of the two linked variables. Figure II.8 presents a simple example of the functioning of electricity systems, illustrated in a causal-loop diagram.

System Dynamics modelling can be seen as a new wave of modelling that questions the previous modelling trends and introduces a method to focus on non-linearities of complex systems. From the beginning, the pioneers of this new approach have faced a number of criticisms[17]. The main criticisms formulated by Nordhaus concern (i) the lack of effort "to identify any relation between [the] model ad the real word" and (ii) the "lack of humility toward predicting the future". Since then, SD modellers have substantially enhanced the methodology to validate[18] their SD models based on Theil decomposition of the mean-square error (Sterman, 1984), structural validity tests and behaviour validity tests (Barlas, 1989), automated calibration (Oliva, 2003) or eigenvalue analysis (Saleh et al., 2010). Besides, contrary to Nordhaus' statement, the use of SD model for policy

[16]Helpful details on this approach can be found in Sterman (2000).
In practice, several computer softwares are specifically designed to implement SD models as iThink® and Vensim®. However, SD approach can be implemented in almost every computer language. SD-dedicated softwares present the advantage to propose ready-made boxes to facilitate the modelling but, in that sense, it also constraints the creativity of modellers.

[17]In particular, the article of Nordhaus (Nordhaus, 1973) constituted a milestone of the controversy on System Dynamics and lead to a number of replies from the supporters of this modelling trend (Forrester et al., 1974).

[18]An example of validity tests of an energy SD model is given in Qudrat-Ullah and Seong (2010).

recommendations does not intend to predict the future. Indeed, it is used to compare different policy options on several possible scenarios in order to estimate their relative performances.

II.2.4.b Contributions of System Dynamics to the understanding of power systems

Since the beginning of SD modelling, this approach has largely been applied to energy systems. For example, roughly 10% of the papers presented at the 33rd International Conference of the System Dynamics Society in 2015 applies System Dynamics to analyse energy systems[19]. Among energy systems, electricity systems have largely been studied by System Dynamics modelling. The article of Bunn and Larsen (1992) can be considered as the pioneer article to study liberalised electricity systems with a SD model. Ahmad et al. (2016) and Teufel et al. (2013) are reference papers for a survey of electricity-related SD models.

SD models allow for a better understanding of electricity systems thanks to the possibility to explicit the different relations involved, as stated in Ford (1997):

> "System dynamics has given us a unique capability to "see the feedback" at work in the power system."

Based on a recent review of 80 papers and SD models applied to the electricity sector, Teufel et al. (2013) establish three main trends: (i) SD models that integrate others methods among which genetic algorithms, decision trees or real options, (ii) SD models with a representation of different risks and (iii) SD models for the analysis of new market designs. The Simulator of Investment Decisions in the Electricity Sector (SIDES) model which has been developed for this thesis (see section II.3) follows this trend by integrating elements of investment decisions and risk aversion theory together with a representation of long-term macroeconomics risks and short-term weather risks in order to evaluate market approaches to trigger investments in wind power by the sole energy market with a carbon price rather than by out-of-market mechanisms (chapter III) and new market design including a capacity mechanism (chapter IV).

[19]Based on our own analysis of the 33rd International Conference of the System Dynamics Society (2015), at least 24 papers out of the 243 conference-papers concern energy systems.

Concerning the understanding of liberalised power markets, SD modelling has been used to analyse investment cycles but also market design including RES-E issues and capacity mechanisms.

Analysing investment cycles

SD modelling applied to power systems has originally been used to analyse the so-called investment cycles. Indeed, SD approach was particularly suitable to study investment cycles because it focuses on temporal evaluation and behaviours, whereas this could not be obtained by optimisation models which focus on long-term equilibria. Ford (1983) is one of the very first modellers to use SD to identify investment cycles in electricity generation[20]. Among others, Bunn and Larsen (1992, 1994), Kadoya et al. (2005), Olsina et al. (2006) and Jalal and Bodger (2010) provide relevant analysis of investment cycles in power systems thanks to SD models.

Analysing market designs including RES-E support mechanisms

Concerning investment in renewables, SD modelling has been used for different purposes including understanding investment incentives under the different support schemes. Tan et al. (2010) combine SD modelling and decisions trees to analyse cash-flows of wind turbines with a special focus on managerial flexibility, but without temporal expansion of RES-E capacity. Fagiani et al. (2013) compare Feed-In Tariff (FIT) and certificate market thanks to a SD model with risk aversion[21]. The effectiveness of tradable green certificates to trigger RES-E development has also been studied by Vogstad (2005) based on a SD model which considers decision rules estimated by laboratory experiments. Based on the same SD model, Ford et al. (2007) further analyse green certificates and highlight effects of an extensive banking or borrowing strategy. However, their modelling of the electricity market is based on the anticipation of the average annual wholesale price rather than hourly electricity prices. This modelling choice enables to eliminate the system variations attributed to changes in electricity market conditions in order to focus on variations due to changes in the tradable green certificates market. Cepeda and

[20] Latter on, Ford (2001, 2002) examines the California's crisis of 2001 with a SD models which simulates investments decisions in peaking plants.

[21] Fagiani et al. (2013) model risk aversion by using an objective function equal to $ENPV - \beta.CVar$ where $ENPV$ is the expected net present value, $CVar$ the continuous value at risk and β the level of risk aversion.

Finon (2013) are the first ones to specifically model market-based investments in RES-E with an endogenous representation of hourly electricity prices. This study shows that a capacity mechanism decreases the market-based development of wind power[22]. More recently, Osorio and van Ackere (2016) propose a SD model with endogenous market-based investments in RES-E after 2035 in the Swiss electricity market, but their modelling uses four representative days rather than the complete hourly variations than may occur during a year. Finally, while SD modelling has been used to analyse some RES-E issues, further insights could still emerge from this approach regarding the understanding of market-based investments in RES-E and their impacts on power systems.

Analysing market designs with capacity mechanisms

System Dynamics modelling has also been used to analyse capacity adequacy issues, and, in particular, different designs of capacity mechanisms. Ford (1999) shows that a constant capacity payment can reduce investment cycles. Focusing on an isolated area, studies by De Vries (2004), Hobbs et al. (2007), Arango (2007), De Vries and Heijnen (2008), Assili et al. (2008), Hasani and Hosseini (2011) and Hary et al. (2016) analyse the effectiveness of different capacity mechanisms in reducing investment cycles and enhancing security of electricity supply. Besides, cross-border effects of interconnected area with different capacity mechanisms have been analysed by Cepeda and Finon (2011) and Ochoa and van Ackere (2015b).

These different analyses of capacity mechanisms by SD models have been carried out in a context of growing electricity demand and generally considering only conventional thermal technologies. Then, further studies are required to assess the effectiveness of these mechanisms in other simulation contexts, in particular mature electricity systems and energy transition policies.

[22]In the study carried out by Cepeda and Finon (2013), wind power is used as a representative mature RES-E.

II.2.5 Comparison of long-term modelling approaches of power markets

As enlightened in the previous sections, different types of models have been used to analysis power systems among which three main families can be distinguished: optimisation models (section II.2.2), equilibrium models (section II.2.3) and simulation models (section II.2.4)[23]. The comparison of these different long-term modelling approaches is presented in the following in order to motivate the choice of SD modelling to study investment issues in power markets under various market designs for promoting renewables or for enhancing capacity adequacy.

Each approach can have its strengths and limits depending on the research topic. Original insights on the long-term functioning of liberalised power system under different market designs can emerge by comparing these different approaches.

Comparing the different modelling approaches is made difficult by the fact that the frontiers between each method can be unclear[24]. Nevertheless, to clarify their respective characters, the discussion starts by proposing a common analytical framework to compare long-term modelling families and to outline their complementarities.

II.2.5.a Common characterisation of long term power systems models

Beyond the modelling family to which it belongs, a long-term model of the electricity sector can be characterised by the three following axis (illustrated in figure II.9):

- The **representation of electricity prices** which is either exogenous or endogenous. With exogenous representation of electricity prices, investment decisions obtained as a result of the model do not influence electricity prices. On the contrary, if the representation of electricity prices is endogenous, the influence of investment decisions on electricity prices is explicitly detailed, for example by the use of a short-term dispatch or by an econometric relationship between installed capacities and electricity prices.

[23] In addition to these three modelling families, levelised costs of electricity are also introduced and discussed in previous section II.2.1 because of its inescapable use in many economic assessments of electricity systems. However, this latter approach remains largely simplified compared to the three other modelling families and thus, is not discussed in this section.

[24] Each modeller would probably have a different opinion regarding the classification and the comparison of the different modelling approach based on its own life experience.

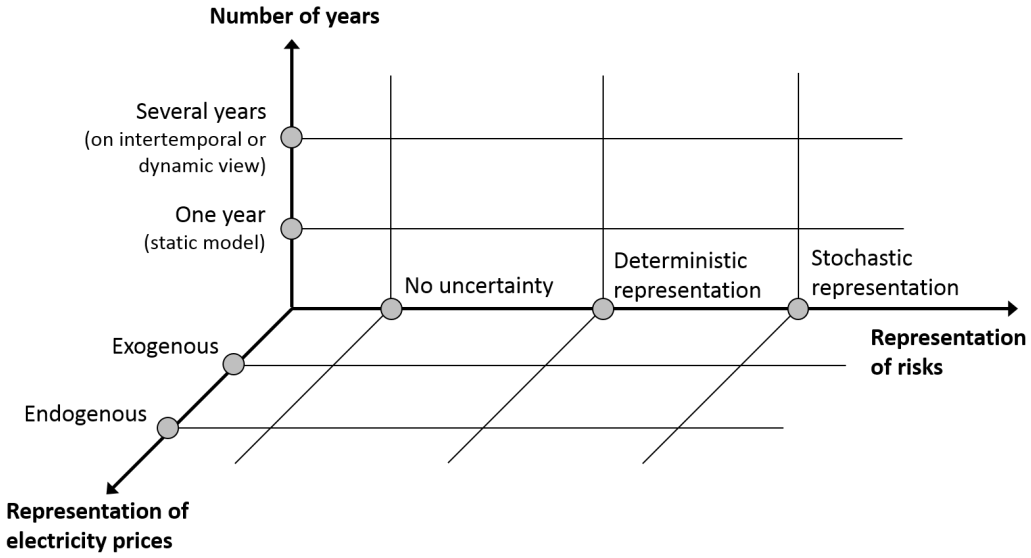


FIGURE II.9: Main characteristics to categorise the different models applied to the power systems.

- The **representation of the risks** associated to the project, which varies between perfect anticipation (hence no risk), deterministic representation and stochastic (probabilistic) representation. Both deterministic and stochastic models can represent risks, but in different ways. A deterministic model always provides the same results for the same set of inputs. On the contrary, a stochastic model can provide different results for the same set of inputs because risky events are generated endogenously by random variables following a certain law of probability[25].

- The **number of years** considered in the model. If the model solves the problem for a given year, it is a called static model. On the contrary, if several years are represented, the model can consider either (i) an inter-temporal view of the future and thus, allows to study the temporal evolution of the generation mix in a context of perfect foresight, or (ii) a dynamic view of the future resulting in the dynamic evolution of the system depending on the anticipation of some risky parameters (typically fuel prices, demand growth, carbon policies).

These three axis (the representation of electricity prices, the representation of risks and the number of years) constitute an analytical framework that can be used to identify the main features and limits of each model.

[25]In practice, from a computational point of view, the seeds of the generator of random variables can be controlled.

Concerning the modelling of risks, a common method is to use Monte-Carlo simulation which consists in testing a representative number of scenarios in order to get a statistical approximation of the results. To be more precise on this subject, Monte-Carlo simulations can be performed by stochastic techniques or deterministic ones. Thus, stochastic Monte-Carlo generation of risks depends on random variables and underlying probability distributions, while deterministic Monte-Carlo generation can be obtained through the use of a set of scenarios chosen as an input of the model (for example based on historical data). The two Monte-Carlo alternatives allow for an adequate representation of risks, if enough runs are conducted in the case of stochastic Monte-Carlo method, and if enough data scenarios are used in the case of deterministic Monte-Carlo method.

In order to illustrate this analytical framework, let us categorise a selection of SD models. As already mentioned, SD models focus on temporal evolution of complex systems and consequently, they all consider a representation of several years with investors making their decisions with a dynamic view of future years. Table II.4 proposes a characterisation of nine SD models applied to power systems based on the two other axis of the proposed analytical framework, namely the representation of electricity prices and the representation of risks. Concerning the modelling of electricity prices, some SD models do not provide an endogenous representation of electricity markets but rather define a relationship (sometimes empirically based) between energy revenues and the system's margin as in Hobbs et al. (2007) and Ford (2001). Others include an endogenous representation of electricity prices (Olsina et al., 2006, De Vries and Heijnen, 2008, Cepeda and Finon, 2011, Hasani and Hosseini, 2011, Fagiani et al., 2013, Ochoa and van Ackere, 2015a) but with different levels of detail, as shown in table II.4. Concerning the representation of risks, whereas few SD models do not consider it (Ford, 2001, Ochoa and van Ackere, 2015a), most of the SD models (Bunn and Larsen, 1994, Olsina et al., 2006, Hobbs et al., 2007, De Vries and Heijnen, 2008, Cepeda and Finon, 2011, Hasani and Hosseini, 2011, Fagiani et al., 2013) represent risks at least on the future evolution of the electricity demand.

	Representation of electricity prices ○Exogenous ; ●Endogenous	Representation of risks ○No ; ●Yes
Bunn and Larsen (1994)	Electricity markets are not explicitly modelled. Only the endogenous anticipation of the loss of load probability is considered.	● Risks on demand by stochastic representation.
Ford (2001)	○ Relationship between average annual price and capacity-demand balance.	○
Olsina et al. (2006)	● Simplified linear load duration curve.	● Risks on the load duration curve by deterministic representation and on outages of power plants by probabilistic representation.
Hobbs et al. (2007)	○ Empirical relationship between energy revenues and system's margin.	● Risks on the energy revenue with deterministic forecast based on past revenues.
De Vries and Heijnen (2008)	● 15-minute prices.	● Risks on the growth rate of electricity demand with stochastic representation.
Cepeda and Finon (2011)	● Discretised load duration curve with 30 steps by year.	● Risks on demand and outages of power plants by stochastic representation.
Hasani and Hosseini (2011)	● Weekly prices.	● Risks on the growth rate of electricity demand by deterministic representation.
Fagiani et al. (2013)	● Daily prices.	● Risks on fuel prices and CO_2 allowance prices by stochastic representation.
Ochoa and van Ackere (2015a)	● 3 representative days per month.	○

Table II.4: Comparison of nine SD models based on the proposed analytical framework.

II.2.5.b Complementarities and differences of the modelling families

Complementarities of using several modelling families

Beyond these differences, some complementaries of the different modelling families can be identified. On the one hand, dynamic optimisation can provide the first best evolution path of a given power system and for a given set of identified risks. On the other hand, if conducted for the same simulation scenario, possible evolution path given the decision process (to be as close as possible to real investment process) can be obtain by simulation modelling. The comparison of the two approaches may provide insightful policy recommendations. Besides, different modelling families can also be combined in order to get new models. In particular, Pereira and Saraiva (2013) propose an hybrid SD-optimisation model that uses an optimisation investment model to defined yearly investment decisions combined with a system dynamics loop to obtain temporal evolution.

Representation of a private investment process

Table II.5 draws a comparison of the three modelling families concerning their representation of the investment process. This comparison table refers to the most common characteristics of the different modelling families, but a given model can include original elements depending on the modeller's objectives. Based on the most common features, optimisation models generally assume perfect rationality, no market power, no construction lead-times and allow for a representation of long-term risks. In turn, microeconomic equilibrium models generally assume perfect rationality, market power, no construction lead-times and do not consider long-term risks. Lastly, simulation models can assume bounded rationality, market power with imperfect competition and they can take into account construction lead-times and a representation of long-term risks. Despite that construction lead-times could be taken into account within all modelling families, it is generally not consider in optimisation models and equilibrium models, whereas it is almost always a native feature of simulation models because of the focus given to temporal evolution of systems.

	Optimisation models	Equilibrium models	Simulation models
Decision	Profit maximisation	Profit maximisation	Economic criterion
Rationality	Perfect	Perfect	Bounded
Market power	○	●	●
Long-term risks	●	○	●
Construction delays	◑	◑	●

Legend: A colored circle (●) means that this element is generally represented, whereas an uncolored circle (○) means that it is generally not considered. A half-colored circle (◑) means that this element could be taken into account but is rarely a native feature. Note: This analysis is based on the most common characteristics of the different modelling families. However, a given model can include original elements depending on the modeller's objectives.

TABLE II.5: Comparison of the different modelling families based on the characteristics of the private investment process.

The possibility to represent realistic investment decision criteria (presented in section II.1) is an originality of simulation modelling. Indeed, optimisation models and equilibrium models which are based on direct profit maximisation (or cost minimisation regarding optimisation models) could hardly be adapted to explicitly take into account these investment criteria. In turn, simulation models can bring insights on the effects of using one or another investment criterion, as various criteria can be easily tested within a given model.

Relevance to the scope of study

The three modelling families can be distinguished by the topics they can inform on. More specifically, concerning the comparison of equilibrium models and SD models, Gary and Larsen (2000) argue that SD models allow for the study of out-of-equilibrium markets which they believe more realistic, whereas equilibrium models assume immediate equilibrium. On SD versus optimisation, Bunn et al. (1993) provide a study based on two models (one SD model and one optimisation model) and they conclude that optimisation is a suitable approach to address the effects of rate of return, capital structure or tax on the long-term equilibrium whereas SD is a suitable approach to address competitive structure of the market including competitive strategies, market incentives to invest and effects of regulatory rules, uncertainty and risks.

In this research, the two key long-term topics to be tackled are: (i) market-driven investments in RES-E (chapter III) and (ii) capacity adequacy under different market designs (chapter IV). Concerning the first topic on RES-E investments, the three modelling families could be used even though the types of insights could differ. Given the specific remuneration challenges faced by RES-E (see section I.3), its market-driven development should be estimated from the point of view of private investors, which is possible with profit-maximising optimisation models, microeconomic equilibrium models or simulation models under different assumptions as presented in table II.5. Regarding the second topic on capacity adequacy, traditional planning optimisation models expressed as a cost-minimisation are not suited to estimate if the price signal is sufficient enough to trigger investments, given that serving electricity is an explicit constraint of the problem. This idea is detailed by Ehrenmann and Smeers (2008):

> "The interest in capacity expansion models came to an almost halt with the restructuring of electricity systems. The idea that competition now drives investments led many to draw the conclusion than planning like models are now obsolete and should be replaced by standard investment analysis or by more or less heroic adaptations of financial models."

Thus, in the literature, capacity adequacy has been analysed mostly by simulation models (Hobbs et al., 2007, Arango, 2007, De Vries and Heijnen, 2008, Cepeda and Finon, 2011, Hasani and Hosseini, 2011, Hary et al., 2016) and equilibrium models with imperfect competition (Creti and Fabra, 2007, Ehrenmann and Smeers, 2008, Fabra et al., 2011, Lambin and Léautier, 2016).

Finally, our methodological choice of SD approach for the model presented in following section II.3 is motivated by the possibility to analyse investment incentives on several years, with a representation of explicit investment decisions criteria, while considering construction lead-times and long-term risks on the demand growth which both shape the temporal evolution of power systems.

II.3 The Simulator of Investment Decisions in the Electricity Sector (SIDES)

"System dynamics modeling can organise the descriptive information, retain the richness of the real processes, build on the experiential knowledge of managers, and reveal the variety of dynamic behaviors that follow from different choices of policies."

Jay W. Forrester, Banquet Talk at the international meeting of the System Dynamics Society, Stuttgart, Germany, July 13, 1989.

This section presents the Simulator of Investment Decisions in the Electricity Sector (SIDES) which has been developed for this research project and which constitutes the analytical framework of chapters III and IV. Further elements on the understanding of the SIDES model are provided in appendix C.

II.3.1 Motivations for the adopted approach of System Dynamics modelling

This subsection gives a brief introduction to the model presented in this chapter by exposing the elements which motivate the choice of System Dynamics (SD) modelling. The underlying reasons are mainly related to the focus given to private investors' decisions in the complex context of hourly power markets.

The study of investments in electricity markets from the point of view of private investors leads to choose a modelling approach which should represent the key characteristics of investment process: (i) economic criterion of private investors, (ii) bounded rationality in their profitability calculations, (iii) investment risks on power markets with variable generating technologies, (iv) long-term risks on the demand growth and (v) construction lead-times which influence the power system's temporal evolution. SD approach

offers these possibilities and constitutes an original methodology[26], compared to classical approaches as optimisation of the generation mix by static or dynamic programming which are familiar to professional experts (electricity firms and consulting groups) and operational research institutes.

Moreover, the modelling approach has to be suitable with mature markets, characterised by limited electricity demand growth and increasing development of Renewable Energy Sources of Electricity (RES-E). This context suggests that endogenous retirement decisions of existing power plants should be represented in the model in order to tackle the issues related to mature markets and energy transition policies based on out-of-market entries of Low-Carbon Technologies (LCT), including variable RES-E.

Finally, the model should be able to finely represent the variability of variable RES-E and its impact on the annual profile of hourly prices by the so-called merit-order effect. For this purpose, it is necessary to consider the 8670 hours of a year, rather than considering typical representative days (generally less than ten days) as in the case of most dynamic optimisation models.

II.3.2 General presentation of the SIDES model

The Simulator of Investment Decisions in the Electricity Sector (SIDES) is a simulation model which belongs to System Dynamics programming. Given assumptions about the initial generation mix, the annual structure of hourly electricity demand, the fuel and carbon prices and the macroeconomic scenarios, the evolution of the generation mix is obtained over several years by endogenous simulation of investment decisions in the various generating technologies and – this is an original feature of the SIDES model – by modelling decommissioning decisions.

[26]For *Réseau de Transport d'Électricité*, the adopted approach should ideally shed new lights compared to the existing or ongoing tools. At the beginning of this research project, simulation modelling was not part of the internal set of methodologies to study investments in power markets under different market designs. Our methodological choice of SD modelling aimed to be innovative by exploring a non-canonical approach of long-term power markets simulation and thus, it can be considered as a relevant approach provided that assumptions on the representation of decision criteria, competition structure and hourly power markets are clearly exposed.

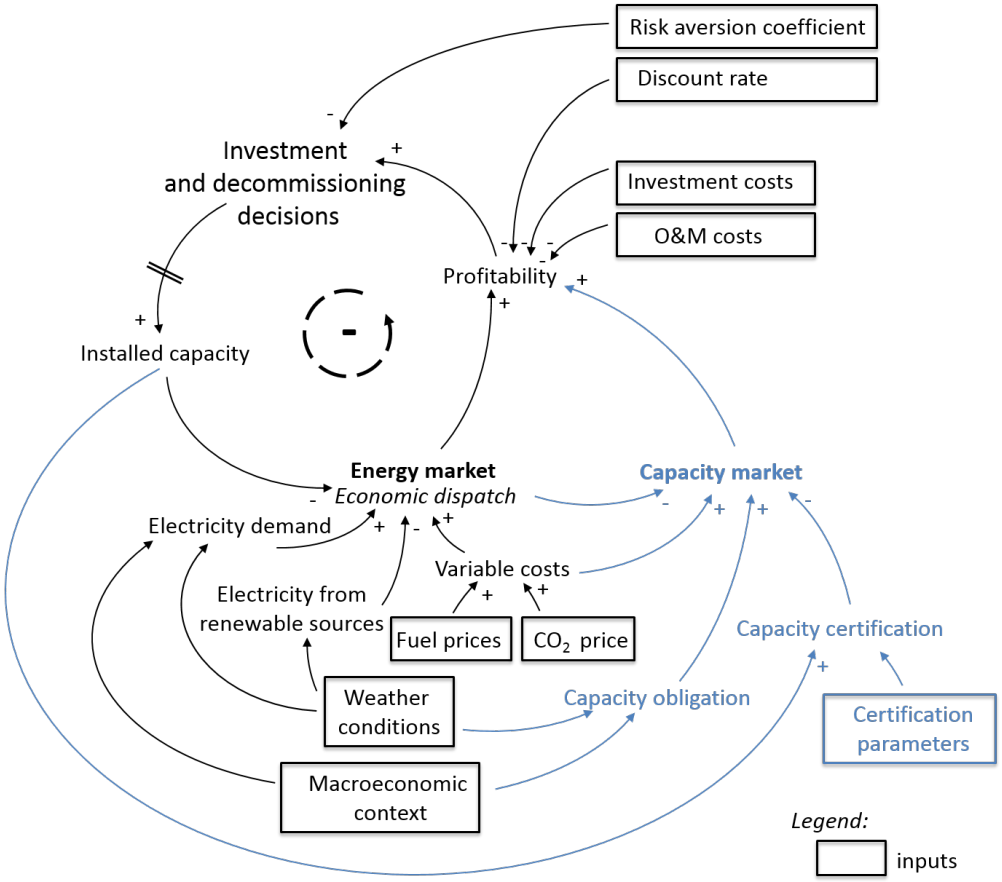


FIGURE II.10: Causal-loop diagram of the SIDES model

The causal-loop diagram[27] of the SIDES model presented in figure II.10 depicts the dynamic process of the simulation for each year. More specifically, the causal-loop diagram allows for the identification of a self-correcting feedback loop, represented by the − sign in the curve arrow: the installed capacity is subject to a stabilising loop because of the effects on the electricity prices and thus on the profitability of the different technologies.

Based on the analytical framework introduced in II.2.5.a, figure II.11 characterises the main features of the SIDES model which are (i) an endogenous representation of electricity prices, (ii) a deterministic representation of risks and (iii) a representation of several years with a dynamic view.

[27]In a causal-loop diagram, causal relationships between two system variables are indicated by arrows and the + (respectively −) symbol specifies positively (respectively negatively) related effect. A curved arrow indicates a feedback loop, which can be either self-reinforcing (represented by the + sign) or self-correcting (represented by the − sign). One should refer to Sterman (2000) for more details on System Dynamics modelling.

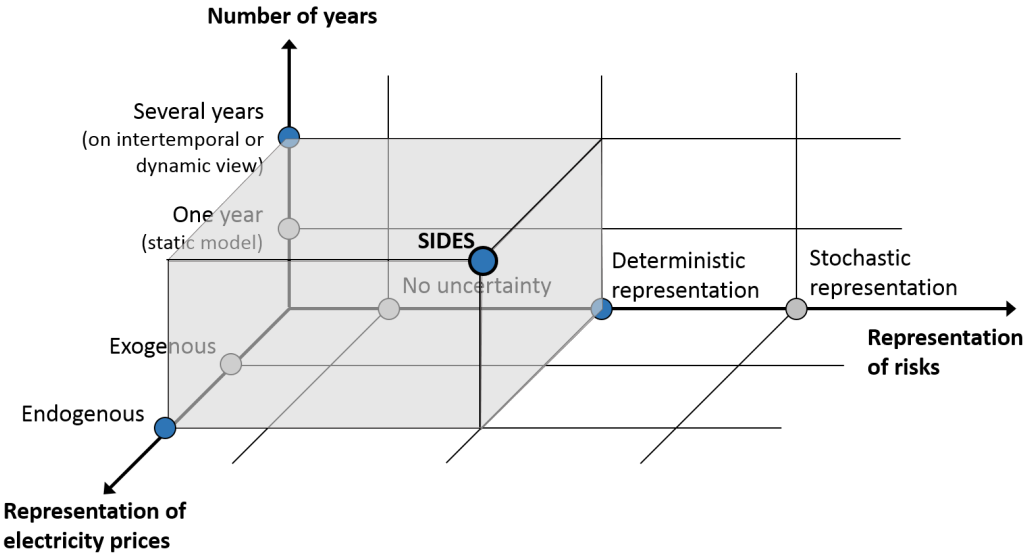


FIGURE II.11: Characterisation of the SIDES model.

More specifically, the SIDES model embeds the basic elements of the functioning of power systems. In particular:

- **Discrete size of power units**: Power units are characterised by their typical nominal power capacity. The investment and decommissioning processes are discrete events: an investment or a decommissioning decision obligatory affects an integer multiple of the nominal power capacity of the considered technology.

- **Investment lag**: For each technology, the time required to build the power plant is taken into account by imposing a delay between the time when the investment decision is undertaken and the time when the power plant is commissioned. However, the model assumes that the decommissioning of an existing power plant occurs immediately on the same year of the decommissioning decision (when decided before the end of the life time of the power plant).

- **Correlation between electricity demand and generation from RES-E**: Undispatchable electricity generation from RES-E is defined by the use of hourly load factors which are correlated to the hourly electricity demand based on historical data.

However, grid functioning is not detailed in the SIDES model. Only one single area is considered under the assumption of *copper plate* and no interconnection with other zones.

Concerning investments in power markets, the SIDES model features a single representative investor that can be viewed as the clustering of all investors. This representative investor is assumed to be technology-neutral and he makes its decision based on an investment criterion which takes into account anticipations of present values under assumptions on risk aversion.

Anticipations of the future by the representative investor

For a given year of a simulation, the private investor represented in the SIDES model should anticipate the future evolution of the system before estimating the economic value of various projects. The SIDES model considers a dynamic representation of future scenarios: for each simulated year, the anticipated future scenarios are updated.

In the SIDES model, the representative investor makes his anticipation of the future on a limited number of years and then, considers that all the future years will be the same (steady state). This **assumption of myopic foresight** is fairly consistent with real investment processes (see section II.1). Besides, myopic foresight has been pointed out as an efficient solution to reduce the complexity of energy optimisation models by Babiker et al. (2009), Keppo and Strubegger (2010) and Babrowski et al. (2014). In particular, Keppo and Strubegger (2010)[28] show that myopic foresight results in postponing investments, thus higher need of capacity on next periods. Concerning SD modelling, bounded rationality is usually assumed and represented by backward looking and extrapolation, combined with a limited window of foresight (Olsina et al., 2006, Hobbs et al., 2007, Assili et al., 2008, De Vries and Heijnen, 2008, Hary et al., 2016).

In the modelling, the representative investor is assumed to benefit from perfect information on the generation mix. More specifically, the representative investor knows (i) the installed capacity of each technology for the present year, (ii) the age of each plant and (iii) his own past decisions including new investments and early closures. Thus,

[28] Keppo and Strubegger (2010) use the energy model MESSAGE and test different assumptions on the window of foresight.

the investor represented in the SIDES model perfectly anticipates the evolution of the generation mix on the following years.

In practice, power plants may face risks from different sources as discussed in section II.1.3. In the SIDES model, the risks that may occur on the costs of the power plants are not represented[29]. However, as the volume risks can be significant, the electricity demand is represented in detail and subject to risks. More specifically, the risks affecting the electricity demand are modelled through two parameters:

- the long-term risk: the demand profile is translated with respect to the anticipated macroeconomic growth;
- the short-term risk: the demand profile depends on weather conditions represented by a set of historical data.

Thus, each year of the simulation, the anticipated demand scenarios result from the combination of the long-term risk (a set of several anticipations of the macroeconomic growth can be used) and the short-term risk.

Representation of power plants

In the SIDES model, all units of a technology are supposed to have the same marginal generation cost. In that sense, there is no difference between new and old units among a technology. Consequently, the corresponding supply function is a step function as illustrated in figure II.12 (solid line). But in reality, marginal cost of new units can be lower than the one of old units, thanks to technical improvements. Thus, the real supply function is probably more similar to the one in dashed line of figure II.12. In that case, if new power plants have slightly lower marginal costs than old ones, considering the real marginal cost function leads to higher incentive to build new power plants which is not taken into account in the SIDES model. The underlying intuition is that this underestimation for new units' revenues is not crucial for the results.

In the following, the type of technology is indicated by χ varying from 1 to the number of considered technologies noted N. The different technologies are ordered by their variable

[29]Even though the SIDES model can represent risks on fuel prices, it is not considered in the scope of this dissertation.

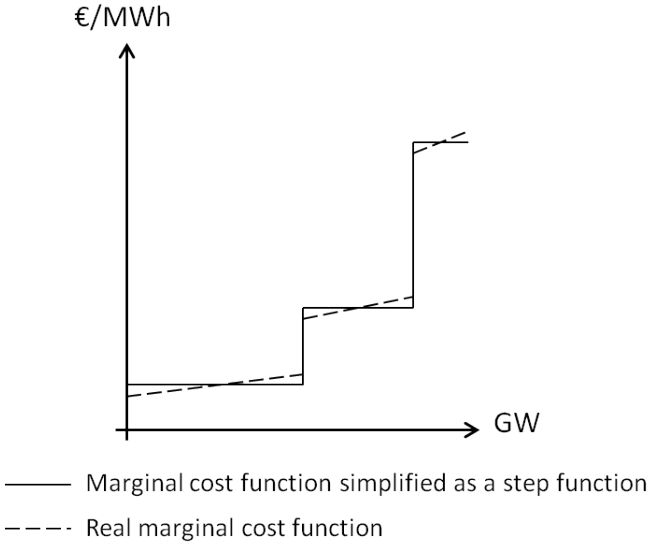


FIGURE II.12: Simulated marginal cost function and real marginal cost function

generating costs (noted VC_χ) from the lowest to the highest: $VC_1 \leq VC_2 \leq ... \leq VC_N$. The installed capacity of the technology χ in year y is noted $K_\chi(y)$. For more details, the complete nomenclature used in this section is detailed in appendix A.

II.3.3 Modelling an energy market

The SIDES model provides a representation of a day-ahead energy market which is supposed to deliver the long-term signals for investment decisions. In order to simulate the evolution of the generation mix over several decades, the market price must necessarily depend on the installed generation mix on an endogenous manner (feed-back loop).

Different approaches to simulate electricity markets can be found in the literature. In particular, the two main approaches are: (i) econometric-based models[30] which link hourly electricity prices to a number of explanatory variables (typically weather-related variables and consumption variables) and (ii) dispatch models based on the merit-order principle eventually with the addition of a number of technical constraints.

In the context of the SIDES model, the second approach is well adapted because it explicitly introduces a relation between the installed capacities of each technology, their respective variable costs and the electricity demand. Another relevant strength of this

[30]Besides, this approach needs to be constructed on past data. Then, the estimation for different future scenarios can be subject to critics.

approach is the possibility to easily model the effect of adding electricity generated by RES-E at zero variable cost. Indeed, it can be done either (i) by subtracting the hourly electricity generated by the RES-E from the hourly electricity demand (thus a net electricity demand) or (ii) by adding the volume available from the RES-E to the merit-order at zero cost on each hour. On the contrary, the effect of RES-E on electricity prices could be more difficult to estimate properly in an econometric-based model.

Definition of hourly prices on the day-ahead energy market

The hourly market price is set to the variable cost of the marginal unit which clears the market. Following the merit order principle, generating technologies are selected from the one with the lowest variable cost to the one with the highest variable cost. The hourly amount of generated power is equal to the load demand except during electricity outages. If instant electricity demand is higher than the total generating capacity, a part of the demand remains unserved and the market price is fixed by the price cap (noted CAP) which can be set to the Value Of Loss Load (VOLL) or another value depending on the case. For each hour h of the year y, the market price is defined by:

$$p(h,y) = \begin{cases} VC_{\chi} & \text{if } \sum_{x=1}^{\chi-1} K_x(y) < L(h,y) \leq \sum_{x=1}^{\chi} K_x(y) \\ CAP & \text{if } L(h,y) > \sum_{x=1}^{N} K_x(y) \end{cases} \tag{II.10}$$

This representation of the electricity market corresponds to a perfect spot market with no exercise of market power: electricity producers offer all their available capacities their marginal generating costs. However, operational constraints of power plants – for example ramping, minimum up-time and down-time – and grid congestion are not part of the modelling. In practice, operational constraints can increase variable costs of thermal plants depending on the shape of the electricity demand. This simplification allows for a simple formalisation of the system operation.

Peak electricity prices are a crucial driver for investments in generating technologies or demand-response programs. The ratio between the marginal cost of peaking units and the price cap is of an order of 10; so that revenues during electricity outages may represent a large part of total energy revenues.

Finally, as the SIDES model focuses on long-term issues, whereas short-term balancing mechanisms are not represented. In that sense, variable RES-E generators do not bear the costs related to the difference between forecasted and actual electricity generation.

Role of RES-E in the day-ahead energy market

Given that the variable generation cost of most RES-E (wind power or solar in particular) roughly equals to zero, generation from RES-E is always the cheapest in the merit-order, when available. Thus, when RES-E are available depending on weather conditions, electricity from RES-E is automatically sold at market price. If the volume of electricity generated by RES-E exceeds load, RES-E generators are not paid for the surplus of generation, contrary to the case of the most present support mechanisms.

II.3.4 Modelling a capacity market

In order to deal with capacity adequacy issues, the SIDES model also provides the possibility for adding a capacity mechanism to the energy market. The considered capacity mechanism corresponds to a decentralised obligation assigned to electricity suppliers, similar to the mechanism proposed in France, or to a forward capacity market with auctioning by the system operator as some US mechanisms as PJM or New England (Finon and Pignon, 2008). The modelling is based on the introduction of a capacity obligation assigned to electricity suppliers in relation to the consumption of their clients. Here, we focus on the electricity producer: he receives capacity certificates and sells them on the capacity market to electricity suppliers for each year. The underlying hypothesis is that the whole cost of the capacity mechanism is transferred to electricity consumers (through retail prices). In this version of the SIDES model, the supply curve of capacity certificates is explicitly and endogenously modelled. The capacity price is obtained on an annual basis by the intersection of the supply and demand curves.

II.3.4.a Adequacy target and certification of equipments

Capacity adequacy target

To contribute efficiently to security of supply, adequacy target should reflect the capacity need of the system under a normalised set of extreme conditions. Parameters are defined so that the capacity obligation corresponds to the peak power demand plus a security margin during critical hours. In the modelling, the capacity target is defined so that this level of capacity ensures a loss of load expectation of 3 hours per year on average over the weather scenarios considered.

Certification of guaranteed available power plants

Capacity certification determines the contribution of a power plant to the capacity adequacy of the considered power system. For thermal units which are supposed to be available at all times, capacity certification (CC_χ) in year y is simply obtained through a normative capacity factor (F_χ) defined for each technology χ thanks to the following relation:

$$CC_\chi(y) = F_\chi.K_\chi(y) \tag{II.11}$$

where $K_\chi(y)$ is the level of installed capacity in year y. For thermal technologies, the factor F_χ simply takes into account the forced outage rate of the power plants.

Certification of variable sources

The case of variable renewables is different. As these units are undispatchable by nature, their contribution to capacity adequacy depends on the effective production during critical hours. Hence, certification of variable energy sources is strongly related to their average availability during peak hours. This is generally referred to as “capacity credit” of renewables. This capacity credit depends on the relative share of variable renewables in the system.

In the SIDES model, the capacity factor of wind power (or any RES-E) is estimated each year depending on the annual load duration curve and wind production share.

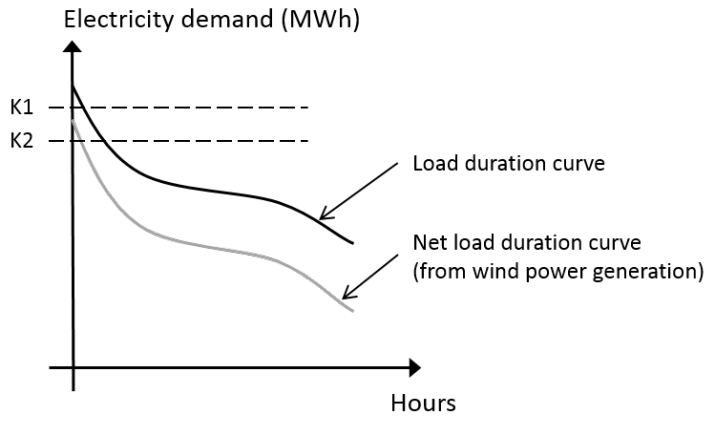


FIGURE II.13: Effect of wind power on net demand obligation (K_1 and K_2) from a load duration curve point of view.

Figure II.13 shows the gross load duration curve (upper curve) which is the effective electricity demand and the net load duration curve (lower curve) after subtracting the electricity generated by undispatchable RES-E. The net load duration curve is obtained by subtracting wind power generation under an assumption of installed wind capacity. On this basis, K_1 and K_2 are respectively the obligation capacity[31] for the gross load duration curve and the net load duration curve. Then, the capacity credit assigned to the installed wind capacity corresponds to the difference between K_1 and K_2. Thus, equation II.12 provides the capacity factor for a variable RES-E noted χ_r for the year y and the installed capacity K_{χ_r} of the considered technology.

$$F_{\chi_r}(y) = \frac{K_1 - K_2}{K_{\chi_r}(y)} \tag{II.12}$$

This approach was applied in several studies (see for example Nicolosi and Fürsch (2009)) to estimate the contribution of renewables to capacity adequacy.

II.3.4.b Capacity pricing

On the capacity market, producers sell their capacity certificates to electricity suppliers that are assigned to the capacity obligation in the decentralised obligation case or to the central buyer in case of a forward capacity mechanism. The supply curve is obtained

[31] Given a load duration curve, the obligation capacity corresponds to the installed available capacity that is needed to meet the adequacy target expressed as a number of hours of loss of load per year.

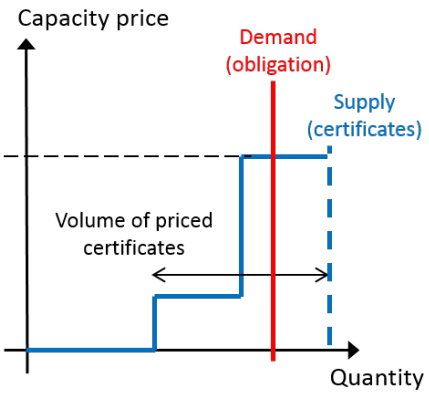


FIGURE II.14: Functioning of the capacity market

endogenously on the basis of capacity price bids, as explained above. The total volume which is bid corresponds to the capacity certificates associated to each technology and obtained by equation II.11 for dispatchable technologies and by equation II.12 for variable RES-E. To simplify the modelling approach, capacity demand is considered as inelastic and its level is aligned on the capacity adequacy target. Then, the clearing capacity price is determined by the intersection of the supply and demand curves as illustrated in figure II.14.

The price offered by a plant owner on the capacity market is a key element in the modelling of this market mechanism. In particular, its definition depends on the situation of the power plant, namely the existing power plants already installed or the plants under construction or else the ones under a forward decision to be built. The bidding strategy on the capacity market could either be defined in relation to annual considerations or in relation to inter-temporal estimations. In the SIDES model, the bidding strategy on the capacity market depends only on annual estimated profitability of power plants, whereas investment decisions are obtained based on multi-annual anticipations. Further elements on the price formation on a capacity market are presented in appendix D. In particular, a useful distinction between short-term and long-term missing money is introduced in this appendix.

Capacity bids of existing plants

For existing plants, the price offered on the capacity market is simply modelled as the difference between annual average energy revenues anticipated for the considered year

and annual Operations and Maintenance (O&M) cost, corresponding to the "short-term missing money" (see appendix D). On their side, investments in variable RES-E are either endogenous (as in chapter III) or endogenously set (as in chapter IV). In the latter case of exogenous development of RES-E, renewable units are supposed to benefit from a specific mechanism (for example Feed-In Tariffs (FITs) or Feed-In Premiums (FIPs)) that ensures their profitability through out-of-market supports and thus, their capacity credits are offered at zero price.

More specifically, to model the bidding behaviour of producers with existing capacities, the price of the capacity bids offered for a given year is assumed to be equal to the difference between the annual O&M cost and the estimated annual energy revenue. Thus, the capacity bid CB_χ offered by an existing power plant of technology χ is defined as:

$$CB_\chi(y) = \frac{1}{CC_\chi(y)}\left(\kappa_\chi OC_\chi - \sum_{h=1}^{8760}\Big(p(h,y) - VC_\chi\Big)EP_\chi(h,y)\right) \tag{II.13}$$

where $EP_\chi(h,y)$ is equal to zero for a given hour h if $p(h,y) \leq VC_\chi$.

This equation represents the behaviour of producers of existing plants under pure and perfect competition conditions.

Capacity bids of new power plants

Considering new power plants, the SIDES model assumes that if existing capacities are not sufficient to cover capacity obligation, new power plant offers a price defined as the difference between anticipated energy revenues and annual fixed cost . In the end, this case leads to a capacity price equal to the lower "long-term missing money" (see appendix D), generally the one of peaking units.

Moreover, in the SIDES model, the bidding strategy assumes that the capacity price drops to zero if certification of existing power plants clearly exceeds obligation with an excess of more than 1%. This is consistent with the theory of capacity requirement if there is no market power, as explained by Stoft (2002).

Finally, for each year of the simulation, the annual capacity price $CP(y)$ is set to the capacity bid which clears the market. Then, for a given power plant of the technology χ, the annual capacity remuneration (noted $CR_\chi(y)$) is obtained by equation II.14.

$$CR_\chi(y) = \begin{cases} CP(y).CC_\chi & \text{if } CB_\chi(y) \leq CP(y) \\ 0 & \text{if } CB_\chi(y) > CP(y) \end{cases} \tag{II.14}$$

II.3.5 Modelling investment decisions

The SIDES model proposes a representation of investment decisions of private investors based on criteria similar to the ones used in practice by firms. It considers both decisions to invest in new equipments and decisions to close existing power plants before the end of their life time.

II.3.5.a Closures of existing power plants

In the context of energy transition, energy efficiency and exogenous development of renewables could lead to early decommissioning of existing power plants. This type of decision is formalised in the model and this represents an innovative feature compared with the state of the art. In the SIDES model, there are two causes for plant closures. Firstly, closures automatically happen at the technical end-of-life of the power plant. Secondly, early decommissioning of an existing power plant can also happen if the power plant is not economically profitable any more.

The first case is easily implemented by storing in memory the age of each power plant and then, by automatically closing the power plants at the end of their life times.

The second case requires to define under which conditions an investor will consider an existing power plant as unprofitable. Because of long pay-out time of power plants, it is not sufficient to anticipate losses on the following year to decide to shut down a power plant. Indeed, a power plant can be unprofitable for one year but can remain on-line because profits are expected on the mid-term. So, in the SIDES model, a two-stage economic evaluation is used to simulate decommissioning decisions.

The first step consists in estimating the net profit of the different technologies for the following year. This profitability estimation is based on energy revenues, capacity revenues and operating and maintenance costs. At this stage, investment costs are not taken into account because they are considered as sunk costs. Indeed, once the power plant has been built, payment of the investment cost is irreversible.

For dispatchable power plant, the annual estimated net revenue (ENP) for the following year (noted $y+1$) is detailed in equation II.15 depending on the annual O&M cost (OC_χ), the hourly energy price ($p(h,y)$), the variable cost (VC_χ), the electricity production on each hour ($EP_\chi(h,y)$) and eventually the capacity remuneration ($CR_\chi(y)$ defined in equation II.14).

$$ENP_\chi(y+1) = -\kappa_\chi.OC_\chi + \sum_{h=1}^{8760} \Big(p(h,y+1) - VC_\chi\Big).EP_\chi(h,y+1) + CR_\chi(y+1) \quad \text{(II.15)}$$

where $EP_\chi(h,y+1)$ is equal to zero for a given hour h if $p(h,y+1) \leq VC_\chi$.

If $ENP(y+1)$ is positive, the power plant is estimated profitable at least for the next year. Therefore, the best decision is to operate the plant at least for the next year. If ENP is negative, the representative investor should wonder whether to close the power plant now or to wait for better economic conditions in the mid-term. In this latter case (if $ENP(y+1) < 0$), the second stage consists in estimating profitability on a longer time period than one year.

In the modelling of the second step decision, the considered period for the economic evaluation is set to five years consistently with the myopic period of five years defined for new investments. The process consists in estimating annual economic balance for the five following years and computing the discounted sum. Thus, mid-term estimated net profit ($MT.ENP$) is equal to:

$$MT.ENP_\chi = \sum_{z=1}^{5} \frac{ENP_\chi(y+z)}{(1+r)^z} \quad \text{(II.16)}$$

where y is the current year in the simulation.

If both ENP and $MT.ENP$ are negative, the power plant is profitable neither on the following year nor on the mid-term and consequently, the unit is decommissioned. If ENP is negative and $MT.ENP$ is positive, the power plant remains in operation because it is expected to recover profitability over the five-year period.

In a third step, the SIDES model also represents annual mothballing decisions of existing power plants[32]. It is formalised in the following way: if $MT.ENP$ is positive but ENP is negative, then mothballing option is tested. Economic evaluation over the five following years is estimated with mothballing and compared to the economic evaluation without mothballing. If mothballing the power plant improves its economic situation, the power plant is mothballed.

II.3.5.b New investments

Most firms base their investment decisions on economic analysis, but have to select some criteria of investment profitability among the large variety proposed in economic textbooks spanning from the well-known Net Present Value (NPV) to real options or portfolio selection (see section II.1). Some academic surveys estimate which economic indicators are actually used by companies to make their decisions. Among others, Graham and Harvey (2001) and Baker et al. (2011) highlight that NPV remains the most common economic criterion for financial decisions. And in particular, Baker et al. (2011) find that 81% of the surveyed firms never use real options mainly because of a lack of expertise or knowledge.

Based on this observations, the SIDES model allows for the simulation of two different investment decision criteria which are further described below: the Internal Rate of Return (IRR) or the Profitability Index (PI) which depends on the NPV of projects. The two criteria provide similar results on the long-term evolution but the selection between the different technologies may differ when focusing on a given year. However, the module of risk aversion was developed only with the PI criterion, because of practical reasons.

The profitability of each technology is estimated based on the comparison of (i) anticipated revenues from the energy market and eventually from the capacity mechanism

[32]The model does not consider short mothballing period within a year.

and (ii) expected costs. In the SIDES model, the cost structure is made of up-front investment cost, annual O&M cost and variable generating cost. Other costs such as settlement for imbalances are neglected.

The SIDES model represents a private investor with myopic foresight. The assumption is that his anticipations of the future are set up to five years ahead the year in progress. Beyond the fifth anticipated future year, all the remaining years are supposed exactly the same as the fifth year (comparable to a steady-state).

Investment decisions based on the Profitability Index (PI)

To reflect the issue raised by the high upfront investment cost of some power plants and in order to discriminate between technologies, the net present value is compared to unitary amount of capital to be spent by plant. So, in this case, new investment decisions are based on a profitability index (PI_χ) defined as the ratio between the net present value (NPV_χ) computed with a discount rate r and up-front investment cost (IC_χ) of the technology χ. The PI is detailed in equation II.17.

$$PI_\chi = \frac{NPV_\chi}{IC_\chi} \tag{II.17}$$

To be more precise, the computation of the NPV depends on the nominal power capacity (κ_χ) of the considered technology, the lifetime (T_χ^L), the up-front investment cost (IC_χ), the annual net revenue ($ENP_\chi(y)$) estimated for each operational year (see equation II.15) and the discount rate (r), as presented in equation II.18.

$$NPV_\chi = -\kappa_\chi IC_\chi + \sum_{y=y(F,\chi)}^{y(F,\chi)+T_\chi^L} \frac{ENP_\chi(y)}{(1+r)^y} \tag{II.18}$$

Investment decisions based on the Internal Rate of Return (IRR)

An alternative investment criterion implemented in the SIDES model corresponds to a comparison of generating project based on their IRR. In this case, it is necessary to define a critical value of the IRR below which an investment project can not be undertaken.

The IRR is classically defined as the discount rate that ensure a zero NPV as detailed in equation II.19.

$$IRR_\chi \text{ defined such as } -\kappa_\chi IC_\chi + \sum_{y=y(F,\chi)}^{y(F,\chi)+T_\chi^L} \frac{ENP_\chi(y)}{(1+IRR_\chi)^y} \approx 0 \tag{II.19}$$

Additional considerations

In order to be selected, the project must respect the two following conditions:

- Investment criterion: its profitability index is positive (or its IRR is higher than the required value depending on the selected investment criterion);
- Additional condition of time-planning: its estimated annual net revenue $ENP_\chi(y(F,\chi))$ for the first commissioning year $y(F,\chi)$ is positive.

The second condition is added in order to introduce a simple way of time-planning into investment decisions. Among the projects selected as just mentioned above, the SIDES model finally determines the project whose profitability index is the greatest to be invested in by the representative investor. Once a project has been chosen to be invested in, a recursive loop enables to estimate if other projects are still economically interesting, while taking into account the investment decisions that have just been made. For a specific simulated year, this recursive loop provides the number of plants of each technology that is invested in.

Besides, in practice, the annual monetary sum that a private investor is likely to invest can be limited by some budgeting constraints. To this end, the SIDES model provides for the possibility to add a constraint, which is expressed either by a maximum capacity to invest each year, or by a maximum investment cost to undertake. The simulations presented in chapters III and IV were carried out with a maximum of 10 GW to be invested in, for each year.

II.3.6 Modelling risk aversion in investment decisions

As presented in section II.1.3 of this chapter, there are several approaches to represent risk aversion in investment decisions. The most common methods are (i) risk-adjusted

discount factor, (ii) mean-variance analysis and (iii) concave utility functions. In some cases, models also feature empirical relations between the value of the project and the level of investments to be undertaken as in Hobbs et al. (2007).

In the SIDES model, the risk aversion is represented through the use of a concave utility function. Thus, instead of taking its decision on the average value of the project as it is the case for risk neutrality, the representative investor makes its decisions according to its utility function and more specifically to the certainty equivalent. This choice was motivated by different reason. Firstly, the use of risk-adjusted discount factor can be criticised for at least two points: (i) it mixes up risk preferences with time preferences (Aïd, 2014), and (ii) from the practical perspective, it is generally defined ex-ante without real estimation of the project's risk, for example using a typical discount factor defined at the firm's level. To overcome this limitation, it is necessary to define a mathematical relationship between a measure of the project's risk and the risk-adjusted discount factor to be used in the economic assessment. Secondly, the classical mean-variance analysis can be criticised on the appropriateness of the variance to estimated risks when the considered variables are not normally distributed. Moreover, this approach is equivalent to traditional utility functions under certain assumptions (see appendix B). Finally, using utility function appears as a relevant solution to model risk aversion in practice, which also easily provides the opportunity for testing different attitudes towards risks by various utility functions.

The utility function employed in the SIDES model corresponds to an exponential function normalised by the mean value of the variable considered, as defined in II.20. As exposed in Raskin and Cochran (1986) and Babcock et al. (1993), the calibration of the coefficient of constant risk aversion α in a classical constant absolute risk aversion function depends on the unit or the size of the variable x. To remove this ambiguity, the variable x is normalised by the mean value of its distribution, hence properties similar to constant relative risk aversion utility functions. This choice was motivated by the fact that the SIDES model uses the same utility function for both new investments and decommissioning decisions for which the values are not of the same magnitude.

$$U(x) = \begin{cases} -e^{-\frac{\alpha x}{|\mu|}} & \text{if } \alpha > 0 \\ x & \text{if } \alpha = 0 \end{cases} \tag{II.20}$$

where x is the net present value in case of new investment or the net profit in case of closure test, α is the risk aversion coefficient and μ is the mean of the anticipated values of x. The case with α equals to zero correspond to no risk aversion.

To take risk aversion into account, decisions of new investment or early retirement are made on the certainty equivalent of the distribution. In case of new investments, the distribution of NPVs is inferred for the different future scenarios that are anticipated by the representative investor. In case of early closures of existing power plants, the net revenues are obtained for the different future scenarios. In both cases, once the distribution is obtained, the expected utility EU is defined as the average value of the utility function computed on the distribution of revenues or NPV. Then, the certainty equivalent (CE) is the value that provides the same utility that the expected utility of the distribution as translated in II.21.

$$U(CE) = EU \tag{II.21}$$

For concave utility function as it the case here, the certainty equivalent is lower than the mean value of the distribution in order to represent risk aversion. Typical values of risk aversion (α) used in chapter IV varies between 0 (no risk aversion) and 3 (the highest considered level of risk aversion). In more concrete terms, considering an equi-probable lottery of earning X or $2X$, a coefficient $\alpha = 1$ corresponds to a relative risk premium of 5.5% of the mean value (here $1.5X$). Respectively, $\alpha = 2$ and $\alpha = 3$ correspond to the relative risk premiums of 10.4% and 14.5% of the mean value.

Risk aversion is taken into account in all the decision-making process of the SIDES model. More specifically, risk aversion is included in three steps of the SIDES model:

- **in the decisions of new investments**: the investment criterion is computed based on the certainty equivalent of the NPVs estimated on the distribution of anticipated future scenarios, instead of reasoning on the average NPV as in the risk-neutral case;
- **in the decisions of early closures**: the certainty equivalent of the short-term net profits estimated on the different future scenarios is used, instead of the average net profit as in the risk-neutral case;

- **in the bids on the capacity market**: generators offer a capacity price aligned on the certainty equivalent of their missing money, instead of the average missing money as in the risk-neutral case.

II.4 Synthesis of the chapter

In liberalised power systems, economic evaluation of electricity generating projects is structured by investors' anticipations of the future and the related risks, and by the choice of the discount factor. Then, investment decisions can be based on different investment criteria, among which common criteria are the Net Present Value (NPV) and the Internal Rate of Return (IRR). Besides, risk evaluation and risk management become increasingly important for private investors given the risks existing in the electricity sector. Uncertainties and risks can be analysed from different perspectives including utility functions, mean-variance objective functions (linked to portfolio theory) or risk-adjusted discount factors. Thus, modelling private investment decisions should correctly integrate some key elements (Botterud, 2003): (i) a process coherent with the decentralised decisions in liberalised electricity systems, (ii) investment timing and construction delays, and (iii) long-term risks.

Long-term modelling of electricity system can be achieved by different approaches among which three modelling families can be identified: optimisation models, microeconomic computable equilibrium models and simulation models (Ventosa et al., 2005). From different perspectives, these three modelling families allow for the study of liberalised power systems under various assumptions on investment process, competition or risk aversion. Among these approaches, System Dynamics (SD) which belongs to simulation models is very suitable to focus on the temporal evolution of the electricity generation mix resulting from private investors' investment decisions. Indeed, SD modelling enables to represent an investment process as close as possible to real investment process, based on economic criteria of private investors with bounded rationality while considering long-term risks and construction delays.

Developed for this research project and belonging to SD modelling, the Simulator of Investment Decisions in the Electricity Sector (SIDES) model simulates the temporal evolution of a given power system on several decades. It considers a representative private investor with various risk aversion assumptions, evolving within different market architectures including the energy-only market but also the addition of a capacity mechanism. It explicitly models both new investment and closure decisions, for a set of conventional and renewable technologies. The detailed representation of hourly electricity markets under perfect competition combined with several weather scenarios enables the

study of power systems with variable Renewable Energy Sources of Electricity (RES-E). Finally, this modelling approach is used to analyse market-based investments in wind power in chapter III and then, to compare different market designs to enhance capacity adequacy in the context of mature markets and energy transition paths in chapter IV.

Chapter III

Development of wind power without support mechanisms

* * *

Investment in renewables are identified as a main challenge to succeed in the transition to a lower carbon economy. Mechanisms devoted to trigger the development of these technologies are also questioned in most liberalised power systems. This chapter studies wind power development within electricity markets with a significant carbon price as the sole incentive. Simulations of electricity market and investment decisions are obtain using the Simulator of Investment Decisions in the Electricity Sector (SIDES) over a 20-year period from an initially thermal system. A range of carbon prices is tested to determine the value above which market-driven development of wind power becomes economically possible.

This chapter starts with an introduction on the development of variable renewable energies, provided in section III.1. Then, section III.2 details the methodology and the case study which are introduced to estimate the practical development of wind power by the sole investment signal of the energy market. Section III.3 presents the simulation results which are then discussed in section III.4. Finally, section III.5 concludes and provides policy insights on the market-based development of variable renewables. This chapter is based on a published article[1].

[1] Petitet, M., Finon, D., and Janssen, T., 2016. Carbon price instead of support schemes: Wind power investments by the electricity market. *The Energy Journal*, 37(4):109-140.

Contents of chapter III

III.1 Introduction

After the oil shocks, energy policies have focused on the reduction of energy dependence and exhaustible resource conservation including a component of R&D and promotion of renewables justified by the social gains associated to these collective goods and the remedies to the market failure in the capture of inter-temporal externalities of technological learnings. After 1990 renewables promotion policies received the backing of climate change activists based on the rationale of reducing carbon externalities. In the electricity sector, Renewable Energy Sources of Electricity (RES-E) have received particular attention in the OECD countries with special support policies mostly based on long term production subsidies, despite the launching of carbon pricing policies based on emissions trading systems, and sometimes on carbon taxes. As discussed in section I.3 of the first chapter, the design of RES-E promotion policy is central to the current European energy debate and has been questioned in a number of academic works (Menanteau et al., 2003, Palmer and Burtraw, 2005, Klessmann et al., 2008).

Today, RES-E support mechanisms – Feed-In Tariff (FIT), Feed-In Premium (FIP), auctioning for fixed-price contracts, certificate obligations – strongly influence the investment choices of electricity producers. While investments in conventional electricity production technologies are mostly driven by anticipations of their market revenues on day-ahead markets, which present important price-risk and volume-risk, the future incomes of RES-E projects are ensured by specific mechanisms which guarantee long term revenues and so, are estimated with a low level of risk. This leads to two investment regimes: (i) one based on anticipations of market prices, sums of discounted net hourly revenues and criteria of risk management and (ii) an out-of-market regime based on these long-term arrangements providing both a production subsidy to non-commercially mature technologies and risk transfer to consumers via the levy financing the cost overruns of the RES-E promotion policy.

However, given the difficulties encountered with current RES-E supports, it is time to challenge their existence. The dilemma is between implementing support mechanisms which guarantee long term revenues to RES-E producers or implementing a regulated carbon price to internalise environmental damages[2]. In the new guidelines on state aids

[2]Among others, Fischer and Newell (2008) use a long term modelling of the electricity market with perfect information to assess the efficiency of different types of energy and climate policies and show that the carbon price is the most efficient option compared to various other types of RES-E support. But,

in environmental protection and energy adopted in April 2014 (European Commission, 2014b), the European Commission supports the integration of renewable technologies into the electricity market by exposing generators to hourly market prices, by the promotion of FIPs instead of FITs and by auctioning contracts for getting this premium and inciting entrants to reveal their costs. In the same trend, different European states have redefined the form of their support for RES-E (electricity market reform in the United Kingdom; Spanish reform; reform of the Renewable Energies Act in Germany; French consultation on RES-E support schemes in 2014, etc.).

Regarding the literature on RES-E in liberalised electricity markets, it mainly focuses on the effects on market prices, residual load curve and generation mix while considering exogenous entries of variable RES-E (see also section I.3). More recently, academic works also focus on defining an optimal system for a set of characteristics of variable generation technologies and on the market value of a MWh generated by RES-E taking into account their integration costs. Firstly, the increasing RES-E capacity significantly alters market functioning by increasing price volatility and lowering average prices (Benhmad and Percebois, 2015), thus endangering the profitability of new investments in complementary thermal technologies for mid-load and peak-load. Indeed, two merit order effects are classically described in the literature: (i) a high level of entry by RES-E producers decreases the average market price by reducing the net demand addressed to thermal power plants (Sensfuss et al., 2008) and (ii) this entrance contributes also to reduce hourly production of thermal units by pushing them out of the merit order more and more frequently. These two effects not only make new investment in thermal units much more risky and threaten coverage of investment costs but also make some of the existing thermal capacities obsolete. Moreover, with sufficient RES-E capacities, hourly market prices are significantly reduced during periods of wind or sun thus a lower market value of RES-E output (Green and Vasilakos, 2011b, Hirth, 2013). Secondly, the residual part of the generation system has to adapt itself in the long term to these artificial entries which reshape the residual load (Holttinen, 2005, Nicolosi and Fürsch, 2009, Bushnell, 2010, Green and Léautier, 2015). In particular, Green and Léautier (2015)

the use of a simplistic representation of electricity markets and cost functions of low carbon technologies leads to an underestimation of the carbon price equivalent to the RES-E supports which are compared with.

highlight that the exogenous entry of wind power progressively results in the phase-out of nuclear, based on the optimisation of the generation mix[3]. Besides, to facilitate the optimal adaptation of non-RES-E capacities, results of RES-E promotion policies should be certain at a forward horizon, while in practice, it is intrinsically uncertain due to the use of a price-instrument (FIT or FIP) rather than a quantity-instrument (obligation of green certificates, etc.). Thirdly, RES-E variability strongly alters short-term mechanisms such as operating reserves. Indeed, system costs (including plant-level and grid-level costs) resulting from the variability of wind power and photovoltaic increase more than linearly with the cumulative RES-E capacity (Keppler and Cometto, 2013). Lastly, market-based development of variable RES-E is rarely investigated carefully in the literature. Cepeda and Finon (2013) propose a modelling of market-based investments in RES-E with an endogenous representation of hourly electricity prices. However, the simulations conducted by Cepeda and Finon (2013) are not pushed far enough to specifically observe endogenous effects of the market-based RES-E development on the power system in particular because investment cost of wind turbines is supposed to decrease in time which automatically results in an explosive wind power development as soon as its economic competitiveness has been reached.

This chapter studies wind power[4] development within electricity markets with a significant carbon price[5] as the sole incentive, rather than an uncertain carbon price signal (as that which emanated from the EU Emissions Trading System (EU-ETS) during its three first phases). In that sense, wind power is invested in under the same regime of other thermal power plants. The carbon price is supposed to be known and constant so that issues raised by its uncertain level are evacuated. Simulation of electricity market and investment decisions by the SIDES model (see section II.3 of the second chapter) is used

[3]This interaction between nuclear power and variable RES-E is particularly relevant because of the low flexibility of nuclear power which faces more volatile net electricity demand when the share of variable RES-E becomes significant. To this end, Green and Léautier (2015) addresses the question of optimising the generation mix given an exogenous capacity of RES-E. This can not be directly compared to the results presented in this chapter which deals with the endogenous competition between nuclear power and wind power in investment decisions.

[4]Because of its closeness to the competitive threshold, on-shore wind power was used as an illustrative case to explore the conditions of market-driven RES-E entry through the incentive of a constant carbon price. Nevertheless, variability profiles of other RES-E technologies (as solar) are quite different from wind profile.

[5]The development of wind power when the carbon price is sufficiently high exacerbates capacity adequacy issues. One answer, which is not represented in the Simulator of Investment Decisions in the Electricity Sector (SIDES) model, is to implement a capacity mechanism with capacity credit allocation differentiated by technologies. In such a case, RES-E units with variable production are inevitably penalised by their low capacity credit and consequently their development is reduced (Cepeda and Finon, 2013).

to trace the evolution of the electricity generation mix over a 20-year period from an initially thermal system. A range of carbon prices is tested to determine the value above which market-driven development of wind power becomes economically possible. This requires not only economic competitiveness in terms of cost-price, but also profitability versus traditional fossil-fuel technologies. Results stress that wind power is profitable for investors only if the carbon price is significantly higher than the price required for making wind power MWh's cost-price competitive on the basis of levelised costs. In this context, the market-driven development of wind power seems only possible if there is a strong commitment to climate policy, reflected in a stable and high carbon price. Moreover, market-driven development of wind power becomes more challenging if nuclear is part of investment options.

III.2 Definition of the case study

III.2.1 Methodology

The study is carried out by using the Simulator of Investment Decisions in the Electricity Sector (SIDES) model described in section II.3 of the second chapter. For the purpose of this study, the main parameters of the SIDES model are the following:

- New investment decisions are based on the Internal Rate of Return (IRR)[6], with a minimum required IRR set to 8% which is consistent with the cost of capital of typical electricity producers as estimated by DGEC (2008).
- The representative investor is risk-neutral. Thus, all the decisions are taken on average values.
- The price cap on the energy market is set to € 3,000 /MWh as it is currently the case on EpexSpot.
- The capacity mechanism is not represented.

The SIDES model is particularly suitable to focus on variable generation because it allows for an endogenous representation of three important effects of variable Renewable Energy Sources of Electricity (RES-E): (i) the negative correlation between hourly variable production and hourly price in opposition to dispatchable plants; (ii) the gradual decrease of the average annual price with the development of new variable RES-E capacities, both of which make fixed costs recovery more difficult and (iii) the feedback loop consisting in the "self-cannibalisation" of variable RES-E competitiveness by its own development and leading to an endogenous limit of their capacities. This latter effect does not exist in the case of out-of-market entries of variable RES-E (under the incentive of Feed-In Tariffs (FITs) or Feed-In Premiums (FIPs)).

The modelling adopted here focuses on the effectiveness of carbon price as a market driver for investment in renewable technologies in an energy only market. A fixed carbon price is added to the model of an energy-only market in order to test carbon policies. This carbon pricing is considered in the particular context of hourly electricity markets

[6]Simulations were conducted for two investment criteria: IRR and Profitability Index (PI). Results are not significantly different.

and their price setting linked to the marginal cost of the overall system. This approach is far from the traditional price setting on average costs with the addition of mark-up as in classic commodity markets.

Given that the variable generation cost of wind power is equal to zero, wind power is always the cheapest generating technology when available. When the wind is blowing, wind turbine generation is automatically sold at market price. If wind electricity generation exceeds load, the wind generator is not paid for its surplus generation, contrary to the case of the present support mechanisms.

Representation of risks

The economic profitability of electricity generating projects is highly sensitive to various parameters (see section II.1.3) such as investment cost, market price, electricity demand, fuel prices, carbon price, electricity generation from RES-E and regulatory constraints on power or technologies (and electricity production from wind turbines). In the SIDES model, the market price is directly related to electricity demand, fuel prices, carbon price and generation mix. Moreover, cost structures and future generation mix (given the past decisions) are assumed to be well known by the single-investor. In the case simulated here, fuel prices remain constant during the whole simulation. Finally, only electricity demand and electricity generation from RES-E are considered as uncertain in the study presented in this chapter.

Besides, in the SIDES model, the considered representative investor makes his anticipation of the future for up to five years and then considers that all the future years will be the same. That myopic foresight is fairly consistent with real investment processes.

- **Electricity demand and electricity generation from wind power**

In the SIDES model, the total annual energy demand in the future depends on macroeconomic anticipations. In this study, the inputs of the SIDES model are defined in order to consider three macroeconomic assumptions which correspond to an annual growth rate of 1%, an annual decrease of 1% and no evolution. Each year of the simulation, annual demand anticipations are adapted to the level selected for the year before. In the short term, electricity demand is also highly sensitive to weather conditions. To represent that sensitivity to the weather, 12 representative demand profiles are used.

Hence, the risks on the electricity demand are represented by two factors:

- the long-term risk: translation of the demand profile with respect to anticipated macroeconomic growth;
- the short-term risk: the demand profile depends on weather conditions.

As with electricity demand, the electricity generation of wind turbines varies significantly with weather conditions. The modelling considered a perfect correlation between electricity demand and electricity generation of wind turbines. The 12 wind generation profiles correspond to the 12 demand profiles. Finally, there are 12 correlated demand-wind generation scenarios.

- **Carbon price**

In the simulations, the carbon price is fixed over the entire period and known by the economic agent. This corresponds to a carbon tax which remains constant over the period. Here, we do not consider an increasing carbon tax which would be a solution to make it socially acceptable in the real world.

- **Number of scenarios to be considered**

In the case where carbon price and fuel prices are fixed and constant over time, the number of future scenarios to be estimated for investment decisions is determined by multiplying the number of macroeconomic assumptions by the number of short-term weather profiles. Each step of the investment decisions and each generating technology are tested for all scenarios.

Different market simulations are computed with different levels of constant carbon price from €0 to €300 /tCO_2 in two scenarios of initial systems and a scope of technology options, the generic one with a pure fossil-fuel based system without nuclear and the diversified one with a system with a mix of fossil-fuel and nuclear plants.

	CCGT	Coal	CT	Nuclear	WT
Investment cost (k€/MW)	800	1,400	590	2,900 - 5,000	1,600
Annual O&M cost (k€/MW/year)	18	50	5	100	20
Annualised fixed cost* (k€/MW/year)	89	167	60	334 - 504	170
Nominal power capacity (MW)	480	750	175	1,400	45
Fuel variable cost (€/MWh)	64	37.5	157	10	0
Carbon emission factor (tCO_2/MWh)	0.35	0.8	0.8	0	0
Construction time (years)	2	4	2	6	2
Life time (years)	30	40	25	60	25

* The annualised fixed cost is computed with annual discount rate of 8% (central assumption of DGEMP (2003) and DGEC (2008)).

TABLE III.1: Economic and technical parameters of generating technologies used in chapter III.

III.2.2 Assumptions and data

Technical specifications of generating technologies

In the simulations, four conventional technologies are considered beside wind turbines (WT): combined cycle gas turbines (CCGT), coal-fired power plants (Coal), oil-fired combustion turbines (CT) and nuclear power plants (Nuclear). Two cases are considered in the simulations: case A is a pure thermal mix without nuclear and case B is a mixed system with nuclear. Two assumptions on nuclear investment cost are considered: a low value of € 2,900 /kW (median case of IEA and NEA (2010), page 103) and a high value of € 5,000 /kW (D'Haeseleer, 2013).

Technical specifications are presented in table III.1. In this case study, wind power and fossil-based technologies are assumed to be mature so that their costs, including investment cost and annual Operations and Maintenance (O&M) cost, are constant over the whole 20-year period. Hence, the study does not consider changes in investment costs or in variable costs, due to the evolution of raw material prices or new technical developments.

The total variable generation cost is equal to the fuel variable cost plus the carbon emission factor multiplied by the carbon price. In the simulations, fuel prices and carbon price remain constant over time in order to facilitate understanding and interpretation

	CCGT	Coal	CT	Nuclear	WT
Capacity in case A (GW)	17.76	57.75	3.50	0	0
Capacity in case B (GW)	17.76	12.2	3.50	46.10	0

TABLE III.2: Initial generation mix (cases A and B)

of the results. However, in reality fuel prices depend on uncertain economic developments. Thus, changes in relative variable production costs may occur as has been the case recently for coal and gas because of the introduction of shale gas in the US. This assumption of constant fuel prices decreases the uncertainty of power plants' revenues and consequently it influences the results of the model. This point is addressed in the following discussion of the results. In the simulations, the capital cost is expressed in constant money and the discount rate is set to 8% in accordance to the central assumption of DGEMP (2003) and DGEC (2008).

In this case study, we do not consider pre-existing wind power capacity which could have been developed under the incentive of a wind power support scheme. We consider an initial generation mix resulting from the optimisation of the central planner on the time-weighted average load curve of the different weather scenarios, without wind power. This thermal generation mix is obtained by the screening curves method (Green, 2006, Joskow, 2006a) on the time-weighted average load curve and approximated to respect the nominal power capacity of each technology. The Value Of Loss Load (VOLL) of the screening curves method is set equal to the price cap of the simulation (€ 3,000 /MWh as defined by EPEXSPOT) in the screening curves method. Table III.2 details the resulting initial generation mix of the first simulated year for both cases A and B. Because the initial mix is set on the time-weighted average load curve, there is still a need of investments at the beginning of the simulations, triggered by the variability in electricity demand due to weather conditions.

Electricity load and wind generation

Electricity demand differs according to weather conditions in the very short term and macroeconomic evolutions which condition the demand growth in the long term. Weather sensitivity of electricity demand is obtained by using 12 different historical demand profiles whose range of variation is shown in figure III.1. Over those 12 scenarios, hourly

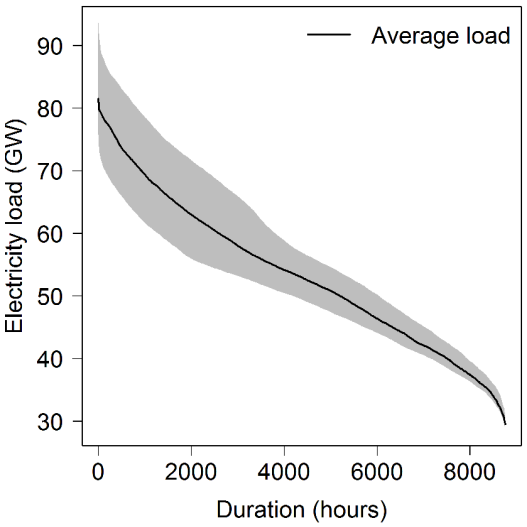


FIGURE III.1: Average electricity demand and its weather sensitivity (shaded area)

electricity load varies between 28.7 GW and 93.6 GW and its mean value is 53.5 GW. Appendix E provides more details on the scenarios of electricity demand and load factors of wind power used in this chapter.

Macroeconomic sensitivity of electricity demand is represented by a vertical translation of the load duration curve. In this case study, three macroeconomic assumptions are used to define anticipated future scenarios, corresponding to +1%, 0% and -1% of annual growth. Thus considering only one assumption on carbon price, each year, investment decisions are taken on the basis of 36 anticipated future scenarios. In simulations, the realised evolution of electricity demand is set to no economic growth and varies only because of its weather sensitivity.

Electricity generation from wind power is correlated to electricity load for each hourly time-step. 12 different wind generation profiles are used, corresponding to the 12 demand profiles. Electricity generation from wind turbines reshapes the net load curves. Initially, the range of variation of power demand between peak and off-peak load is 59.6 MW on average over the 12 historical weather scenarios. The entrance of 45 GW of wind power increases the range of variation of the net load curve to 73.6 GW on average (+23.5% compared to real electricity load). The hourly load factor of wind power varies from 0.05% to 79.5% depending on weather conditions and its mean value is 21.6%.

III.3 Results

III.3.1 Wind power in an initial pure fossil-fuel based system

III.3.1.a Dynamics of the generation mix

The SIDES simulations show that the threshold value of the carbon price beyond which wind power is selected by the representative investor is € 70 /tCO_2. The electricity generation mix over time varies in relation to the carbon price. Figure III.2 shows in each simulation the evolution of the technology mix. Below € 65 /tCO_2, no wind power appears in the generation mix. With this value, only a marginal wind capacity of 3.2 GW is installed during the twenty years of the simulation. As shown in figure III.3 and detailed in table III.3, as the carbon price jumps to € 70 /tCO_2 and above € 80 /tCO_2, capacity development of wind turbines increases sharply and reaches respectively 37.7 GW (15.3% of the annual production) and 74.2 GW (30.0% of the annual production) over

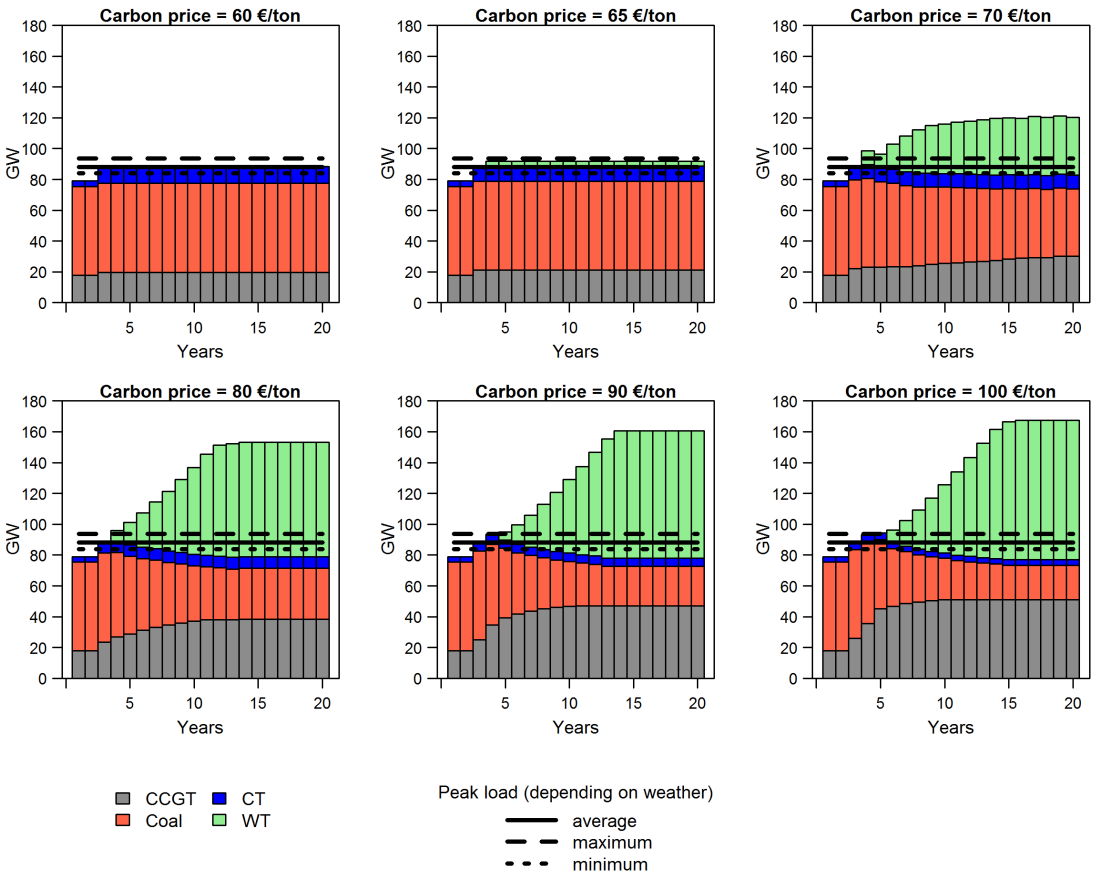


FIGURE III.2: Installed capacities (GW) over time for different carbon prices [case A].

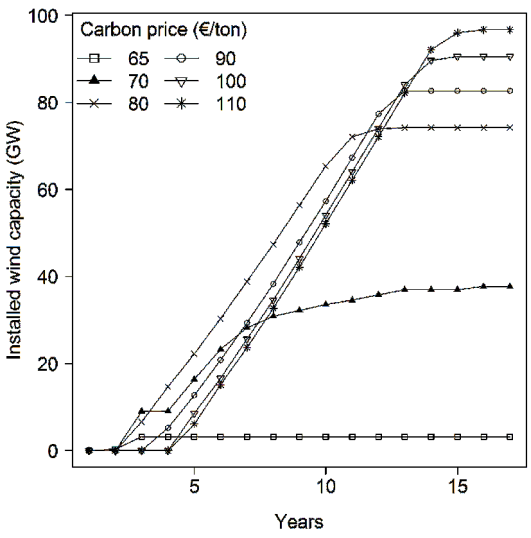


FIGURE III.3: Installed wind capacity over time for different carbon prices [case A].

Carbon price (€/tCO_2)	CCGT (GW)	Coal (GW)	CT (GW)	WT (GW)	Total thermal capacity (GW)
60	19.7	57.8	11.0	0	88.5
65	21.1	57.8	9.8	3.2	88.7
70	30.2	44.3	8.9	37.7	83.4
80	38.4	33.0	7.5	74.2	78.9
90	47.0	25.5	5.4	82.6	78.0
100	50.9	22.5	3.5	90.5	76.9
110	53.8	20.3	2.5	96.7	76.5

TABLE III.3: Generation mixes at the end of the simulation for different carbon prices [case A].

the twenty-year simulation. Then, the growth of installed wind capacity for each additional € 10 /tCO_2 slows down, corresponding to the "cannibalisation" effect of wind power development on its competitiveness. In other words, this saturation of wind power development is explained by the gradual decrease in the economic value of wind power, as more wind power capacity are already installed. Moreover, it is not common to observe that 96.7 GW in wind power capacity replace de facto 12.0 GW of thermal capacity in the scenario with a carbon price of € 110 /tCO_2 versus the scenario with the price of € 60 /tCO_2 which does not make any wind power investment profitable for private investors.

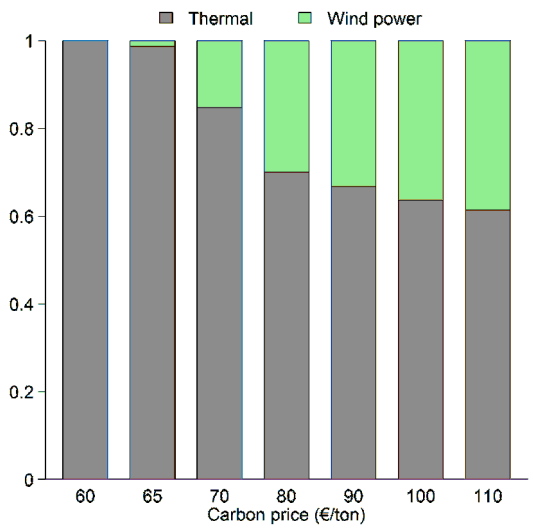
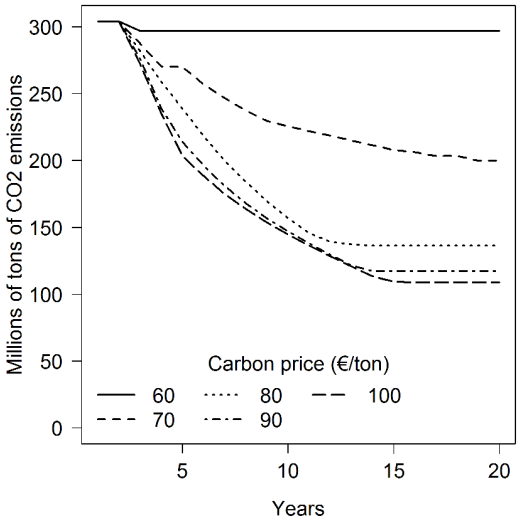


FIGURE III.4: Share of electricity production from thermal and wind power at the end of the simulation (on average over the 12 weather scenario) for different carbon prices [case A]

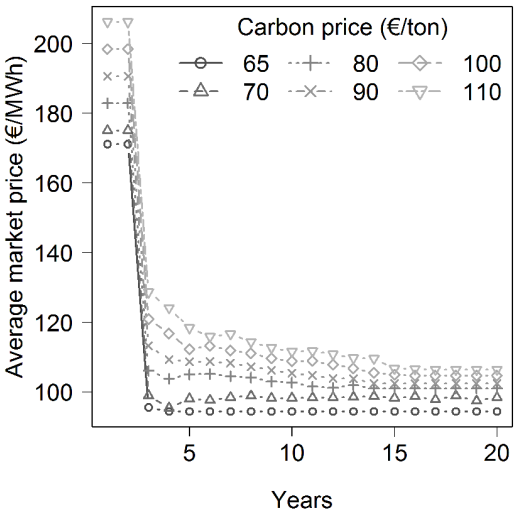
Carbon price (€/tCO_2)	65	70	80	90	100	110
Share of wind capacity	3.5%	31.1%	48.5%	51.4%	54.1%	55.8%
Share of wind energy	1.3%	15.3%	30.0%	33.3%	36.3%	38.6%

TABLE III.4: Annual share of wind capacity and energy (mean value over the 12 weather scenarios for the generation mix at the end of simulation) [case A]



Notes: This does not take into account CO_2 emissions from the construction of power plants.

FIGURE III.5: CO_2 emissions from electricity generation over time for different carbon prices (average values for weather scenarios) [case A].



Notes: The first wind farms come on line in years 4 to 6 of the simulation, depending on the case considered.

FIGURE III.6: Evolution of the yearly average market price on the 20 years of the simulation for different carbon prices (average values for weather scenarios) [case A].

This evolution under the effect of carbon price increases comes at the expense of coal. The profitability of coal plants decreases rapidly and more than the new CCGT's profitability when carbon price increases. Below € 60 /tCO_2, coal is the baseload technology of the system. Above this value, its variable cost is higher than the variable cost of CCGT and thus, CCGT becomes the baseload technology. The profitability of coal-fired power plants decreases when the carbon price increases. Finally, the number of decommissioned coal power plants increases with the carbon price (figure III.2). Consequently, as coal capacity decreases and electricity generation from wind power increases, fossil-fuel use is reduced. Thus, CO_2 emissions decrease significantly as shown on figure III.5. A carbon price of € 70 /tCO_2 decreases CO_2 emissions by 22% over the twenty years of the simulation, compared to the case of € 60 /tCO_2 with no development of wind power. The decrease of CO_2 emissions which is highlighted here is explained by two elements: (i) the development of wind power and (ii) the partial replacement of coal power plants by CCGTs. However, in reality, the decrease of CO_2 emissions can be achieved by many other means that are not considered in the simulations, as for example by carbon capture and storage, demand-side management or other Low-Carbon Technologies (LCT) or Renewable Energy Sources of Electricity (RES-E).

In figure III.6, for a given year, the average market price is higher when carbon price

increases. At the same time, for a given a carbon price, the average market price globally decreases in time consequent to the development of wind power.

III.3.1.b Energy spill-overs

When wind capacity increases, electricity spill-overs become more frequent and occur when electricity demand is low and the wind blows. Figure III.7 shows the average amount of electricity spill-over (hours and volume) for generation mix at the end of the simulation, on average over the 12 weather scenarios. It underlines that above € 80 /tCO_2, large volumes of electricity are spilled over.

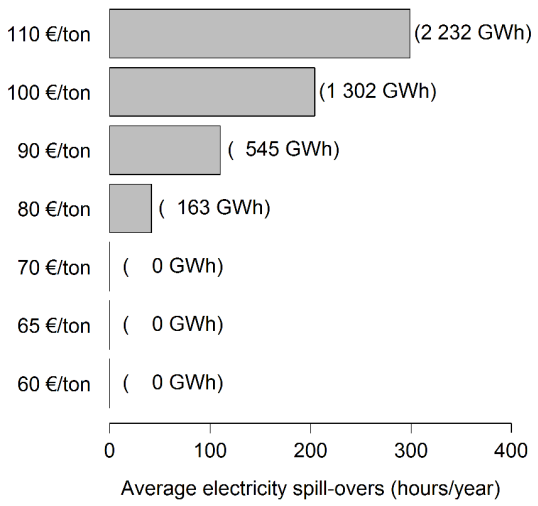
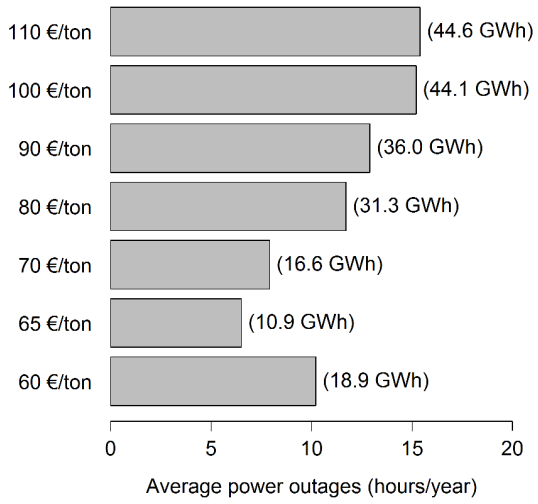


FIGURE III.7: Average hours and volumes of electricity spill-overs, over the 12 weather scenarios for different assumptions on carbon price [case A].

III.3.1.c Power outages

One of the majors concerns about the development of RES-E is the increase of electricity outages when production from wind power is low. In order to quantify this effect, hours and volumes of electricity outages was computed on the 12 weather scenarios for the generation mix obtained at the end of the 20-year simulation for each carbon price (Figure III.8). When the carbon price is € 60 /tCO_2 with no wind power development, there is an average of 10 hours of electricity outage per year. This value could seem to be high but it is explained by the assumption on the price cap (€ 3,000 /MWh) considered in the simulations.

When wind capacity increases with the carbon price in successive scenarios of carbon price, total thermal capacity is lower (see table III.3). This effect threatens the security of supply of the electricity system because the total thermal capacity is not sufficient to serve all the electricity demand in random situations when electricity demand is high and wind does not blow. Figure III.8 shows the increase of the average electricity outages (in number of hours and volume) on average over the 12 weather scenarios. Figure III.8 also underlines that when few wind capacities are being installed (for a carbon price of € 65 to € 70 /tCO_2), electricity outages are slightly reduced because a relatively small volume of thermal capacity is closed due to the development of wind power. For



Note: the price cap on the energy market is € 3,000 /MWh.

FIGURE III.8: Average hours and volumes of electricity outages (on average over the 12 weather scenarios) for different assumptions of carbon price [case A].

higher carbon prices, the development of wind capacity in the succession of scenarios with higher carbon price decreases the security of supply.

III.3.2 Wind power in a system with the nuclear option open

In the previous sub-section, nuclear was not considered in the generic case in which wind power plants are compared to fossil-fuel technologies. But what if nuclear technology is an acceptable option in a country? Another set of simulations is conducted in order to highlight the impact of a nuclear option on the profitability of wind power investment along the different steps of carbon price increase. Two nuclear policies are tested: case B-1 is to maintain only the existing nuclear capacity at its initial level (moratorium on new nuclear investment), and case B-2 is to allow new nuclear development from this initial capacity. For this latter case, two contrasted hypothesis on nuclear investment cost are tested: € 2,900 /kW in case B-2/H1 according to the value proposed in the median case of the report of IEA and NEA (IEA and NEA (2010), page 103) and € 5,000 /kW in case B-2/H2 according to D'Haeseleer (2013). These two assumptions result in a Levelised Cost Of Electricity (LCOE) of nuclear which is set equal to € 54.6 /MWh in case B-2/H1 and € 77.7 /MWh in case B-2/H2.

Details on nuclear assumptions are presented in table III.1. The initial generation mix with nuclear (table III.2) corresponds to the optimal mix obtained as above by the method of screening curves on the average load curve, with an initial nuclear capacity of 46 GW for a maximum load of 89 GW.

III.3.2.a Existing nuclear but moratorium imposing no new investment in nuclear (Case B-1)

In case B-1 without new investments in nuclear – so that nuclear capacity remains 46 GW over the 20-year period – the carbon price must be very high to trigger investments in wind power (table III.5). In fact, nuclear plants are insensitive to carbon pricing because they benefit from their low variable cost together with the fact that this source of electricity does not emit Greenhouse Gas (GHG). In particular, nuclear remains more economically relevant for investors than wind power even with any high level of carbon price. So, nuclear strongly impacts the market-driven development of wind power plants.

Carbon price (€/tCO_2)	70	80	90	100	110	150	200	250	300
Wind capacity (GW) - Case A without any nuclear	37.7	74.2	82.6	90.5	96.7	119	140	159	175
Wind capacity (GW) - Case B-1 with existing nuclear (46.1 GW)	0	0	0	0	0	4.9	14.4	21.2	26.8

Table III.5: Wind capacity at the end of simulation for different carbon prices with and without existing nuclear capacities [cases A and B-1]

Not only does the development of wind capacity occur at a much higher carbon price level, but this development occurs at a very slow pace and with a much narrower span.

III.3.2.b Existing nuclear and new investments in nuclear allowed (Case B-2)

In case B-2/H1 and B-2/H2 in which nuclear plants are politically allowed for investment, wind power development is still more slowed down. With the low assumption of € 2,900 /kW (case B-2/H1), simulations were conducted for a range of carbon price from € 0 to € 500 /tCO_2. Even with the value of € 500 /tCO_2, no wind power appears in the generation mix. With the high nuclear investment cost of € 5,000 /kW (case B-2/H2), wind power capacities are invested in if the carbon price reaches € 300 /tCO_2. But it remains at an anecdotal level: only 2 GW of wind power with this value and 13 GW with a carbon price of € 500 /tCO_2.

These results suggest that existing nuclear plants not only impede profitability of wind power projects up to a high carbon price level of € 100 /tCO_2 (as in case B-1), but with the phase-in of new nuclear, it appears that new nuclear investment could be the most profitable option of non-carbon power development under the incentive of higher and higher carbon prices Consequently, market-driven investments in wind power appear to be feasible only if the nuclear option is politically rejected.

III.4 Discussion

III.4.1 Cost-price comparison of fossil-fuel technologies and wind power

This section proposes a comparison between the results obtained by Simulator of Investment Decisions in the Electricity Sector (SIDES) simulations and a cost-price analysis based on the Levelised Cost Of Electricity (LCOE) (see section II.2.1). It underlines that the carbon price estimated by simulations is higher than the one suggested by LCOE analysis. This difference is due to the cost inherent to non-dispatchable generation which suffers from weather uncertainty (as exposed in the following) and consequently, it should not be seen as a market failure.

The LCOE is the average cost of producing a MWh taking into account investment cost, Operations and Maintenance (O&M) cost and variable generation cost which includes the carbon cost resulting from the carbon pricing. This concept is presented in section II.2.1.

Given the cost structure considered here and given that the volume of electricity generated each year is supposed to remain constant over time, the LCOE can be computed as in the simplified equation III.1 for a technology χ involving the investment cost (IC_χ), the annual O&M cost (OC_χ), the variable generation cost (VC_χ), the load factor (Lf_χ), the lifetime of the power plant (T_χ^L) and the discount rate (r).

$$LCOE_\chi = VC_\chi + \frac{1}{8760.Lf_\chi}\Big(OC_\chi + \frac{IC_\chi.r}{1-(1+r)^{-T_\chi^L}}\Big) \tag{III.1}$$

As mentioned in section II.2.1, LCOE is widely employed to assess the respective cost-prices of electricity of each generating technology and to determine the most economic technology at the margin of the system. However, comparison of LCOEs with hypotheses on load factor is relevant if conducted for a same group of technologies. Here, the objective is to compare the LCOEs of base-load and mid-load units (coal, CCGT) which could produce at any time, with WT which is not dispatchable, but which produces randomly at any hour of the year. This comparison is valid if we suppose that the value of a MWh is the same at any hour of the year on the electricity market. We do not consider peaking units (high variable cost but low investment cost) because they are dedicated to generating power during peak and extreme peak periods.

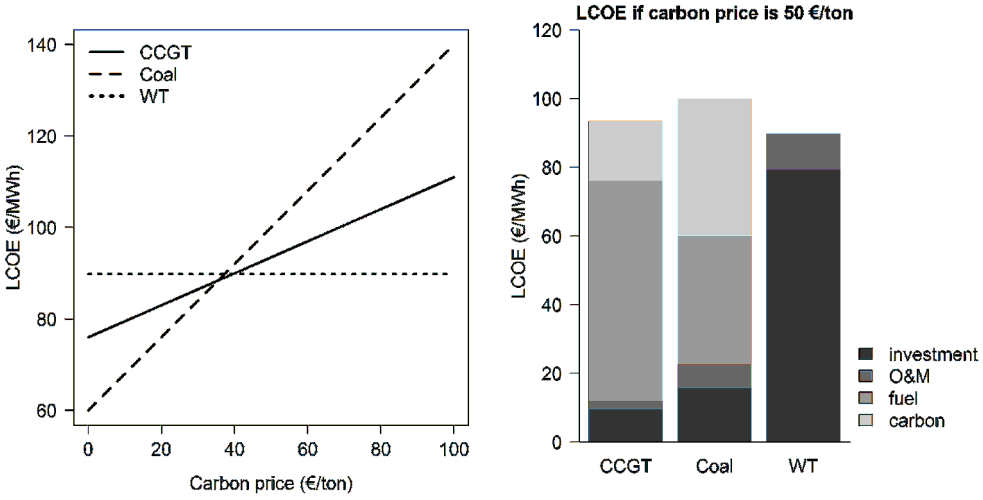


FIGURE III.9: Levelised cost of electricity as a function of carbon price
Notes: The discount rate is equal to 8%. The thermal load factor is 85%.

Plant parameters are those presented in table III.1. LCOE is sensitive to the load factor. For thermal power plants (CCGT and Coal), we consider a load factor of 85% (IEA and NEA, 2010). The wind power load factor computed from the data used in the simulation tool (average load factor over the 12 generation profiles) is equal to 21.6%. Figure III.9 presents the evolution of LCOEs at different carbon prices.

On the basis of LCOE analysis, wind power is cheaper than coal and CCGT if the carbon price is above € 39.5 /tCO_2. But, the LCOE of wind power corresponds to fixed costs (that is to say, investment cost and O&M cost) while variable costs are an important share of the LCOEs of fossil-fuel plants which increase when the carbon price increases. Consequently fixed costs represent less than 38% of LCOE. Table III.6 details LCOE and specifies the fixed cost share. This difference is crucial when looking at investments because the market price is always greater than or equal to the variable cost of plants that produce electricity at the time, given that it is aligned on the marginal cost of the costlier fossil-fuel plants which clear the hourly market. The recovery of fixed costs of the wind power units with their infra-marginal surplus on hourly markets will be much more uncertain than the same fixed cost recovery of the fossil-fuel units. So the selection of technologies by the investors is done with reference to their profitability from their anticipated revenues on the hourly markets rather than their competitiveness in terms of their respective cost-prices.

As underlined by Joskow (2011), LCOE comparison considers that electric energy is “a

Carbon tax scenario (€/tCO$_2$)	**0**	**50**	**100**
CCGT LCOE (€/MWh)	76.0	93.5	111.0
Fixed cost share	15.7%	12.8%	10.8%
Coal LCOE (€/MWh)	60.0	100.0	140.0
Fixed cost share	37.5%	22.5%	16.1%
Nuclear H1/H2 LCOE (€/MWh)	54.9 / 77.7	54.9 / 77.7	54.9 / 77.7
Fixed cost share	81.8%/87.1%	81.8%/87.1%	81.8%/87.1%
WT LCOE (€/MWh)	89.8	89.8	89.8
Fixed cost share	100%	100%	100%

Table III.6: Levelised cost and fixed cost ratio for different carbon prices

homogeneous product governed by the law of one price" which makes the comparison of LCOE for renewable electricity sources and conventional technologies not economically relevant. But in fact, the value of a MWh varies with hours of day, week and season on the year when the MWh is generated. Triggering investment cannot be easily deduced from LCOE comparison (which is a cost indicator). The investment process is much more complex that a simple comparison of technologies' costs. The economic profitability of a generating power plant depends on its investment cost compared to the gap between variable cost and market price on each hourly market during the economic lifetime of the equipment, rather than total generation cost.

In fact, dispatchable generating technologies allow producers to choose when their power plants generate electricity and thus maximise their value on the hourly energy markets. More specifically, producers bid on the hourly markets and then, produce electricity only if their bid is cheaper than (or equal to) the marginal clearing one. On the contrary, wind power producers cannot decide whether or not their plants generate electricity. Their moments of reliability are random and quite limited. Consequently, if we suppose that their forecasts is quasi perfect, wind power producers could bid at zero price when they anticipate to be able to generate electricity and are sure to be selected. But, they cannot maximise their profits by producing when the market price is the highest.

To illustrate this difference between dispatchable and non-dispatchable units, figure III.10 shows the time-weighted average price and the wind-profile-weighted[7] average price in the simulation with a carbon price of € 100 /tCO$_2$. The graph clearly underlines that

[7]Whereas the time-weighted average price is the classical mean value of hourly prices, the wind-profile weighted average price corresponds to the mean price received by a wind power generator having the average wind profile.

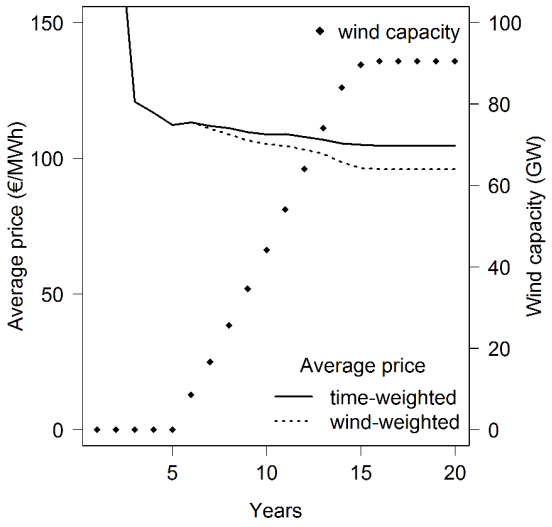


FIGURE III.10: Time-weighted and wind-weighted average price over years for the simulation with a carbon price of € 100 /tCO_2 (for each year, on average over the 12 weather scenarios).

when wind capacity increases, wind-weighted average price becomes significantly lower than time-weighted average price. In this illustrative case, the value factor[8] of wind power is 0.92 for an installed wind capacity of 90.5 GW corresponding to 36.3% of electricity generated by wind power. Hirth (2013) estimates a lower value factor of wind power, in the range of 0.5-0.8 at a market share of 30%. Green and Vasilakos (2011b) also highlight this effect of lower market prices when wind power produces and estimate its magnitude for Denmark. This difference can be explained by a difference in the mix structure as in this case, there is no nuclear.

Finally, despite wind power's competitiveness in terms of cost-price when the carbon price is above € 40 /tCO_2, wind power is weakened by its non-dispatchable nature and the share of fixed cost to be recovered by revenues on quite volatile hourly markers, compared to fossil-fuel technologies. The simulations carried out with the SIDES model support this intuitive difference. Indeed, the threshold value of € 70 /tCO_2 given by SIDES simulations is considerably higher than the value of € 40 /tCO_2 for wind power competitiveness obtained by the LCOE method. This shows clearly that the hourly electricity markets do not give an economic value to the MWh coming from variable wind generators in the same way as those of dispatchable plants.

[8]The value factor is defined as the ratio between the wind-weighted average market price and the time-weighted average market price.

III.4.2 Profitability of wind power

This section discusses how and when wind power begins to be selected and then emerges as a central option for investors. With the market-based selection of investment in the different technologies, the investment process in new power plants is based on the calculation of the Internal Rate of Return (IRR) of every possible project of each technology. Then, investments are obtained by selecting projects from those with the highest IRR and going down to the one which clears the need for new.

Carbon price has an effect on the electricity market price and on the respective profitability of the various generating technologies. The explanation of the increase in the IRR of the wind power stays in the combination of two opposite effects of the higher level of carbon price from one SIDES simulation to the next one as shown in figure III.6 which displays the yearly average market price for different simulation cases. Indeed, the market price is influenced by two effects (observed in figure III.6):

- **A direct effect**: an increase in the carbon price pushes up the variable costs of thermal units and consequently, this increases hourly market prices. In other words, the thermal units do not make more profit while the wind power units show better hourly revenues.
- **An indirect effect**: an increase in wind capacity lowers the market price (because the variable cost of wind power is zero).

III.4.3 Energy spill-overs and power outages

When wind capacity increases with carbon price, both spilling over and electricity outages occur (figures III.7 and III.8), but the underlying economic problems are not the same: the first does not raise social efficiency issues while the second one does.

The increase in energy spill-overs is economically acceptable for investors in wind power units because investment decisions under the incentive of a higher carbon price have been made after having assessed the profitability of these new units, even with a share of their production which could not be physically absorbed by the system load demand over a significant numbers of hours. This puts forward the growing importance of inter-temporal arbitrage with Renewable Energy Sources of Electricity (RES-E) development,

including electricity storage and electricity demand side management. Inter-temporal arbitrages are crucial to deal with wind intermittency and improve the security of supply of the electricity system.

On the contrary, the degradation of the security of supply and its social costs raises an issue of regulatory imperfection. This problem of security of supply related to wind power deployment is created by the low price cap at € 3,000 /MWh which does not reflect the social dis-utility of not being supplied. The price cap impedes price spikes of sufficient magnitude to generate a sufficient scarcity rent and encourage investment in peaking units.

III.4.4 Sensitivity of the results to plant parameters and market design

In this last part of the discussion, some assumptions and their implications on results are discussed.

As mentioned previously, fuel prices and cost assumptions for both thermal an wind power plants remain constant over the 20-year simulations. However, it will obviously not be the case in reality. Nevertheless, this assumption is necessary to simplify the analysis of the results. Our objective is to assess the influence of carbon price on market-driven investments in wind power and to highlight the difference between the carbon price needed for wind power development obtained by LCOE analysis and SIDES simulations. The latter is not affected by a change in fuel prices.

III.4.4.a Investment cost of wind power

To assess the sensitivity of the results to the investment cost of wind power, another series of simulations was conducted with a lower value of the investment cost of wind turbines of € 1,200 /kW instead of € 1,600 /kW. This second assumption corresponds to a decrease of 25% of WT investment cost. Except this assumption on the investment cost of wind power, others parameters of the simulations are the same as in case A. The results confirm this significant gap between the carbon price which could make the WT competitive with CCGT in terms of LCOE and the one which allows for sufficient profitability of wind power. Table III.7 presents the wind capacity obtained at the end of simulations for different carbon price with the assumptions of case A and with the

Carbon price (€/tCO_2)	20	30	40	50	60	70	80	90
Wind capacity (GW) - Case A	0	0	0	0	0	37.7	74.2	82.6
Wind capacity (GW) - WT investment cost of €1,200 /kW	0	3.6	17.7	91.2	109	120	127	132

TABLE III.7: Wind capacity in case A and sensitivity to investment cost of wind power

low assumption on WT investment cost (€ 1,200 /kW). The results in relative terms are quite the same. On one hand, LCOE analysis suggests a carbon price of € 17 /tCO_2 to make wind power competitive with thermal power plants. On the other hand, system dynamics simulations show that a carbon price of € 30 /CO_2 is needed to see market-driven investments in wind power. With this value of € 30 /tCO_2, 3.6 GW of wind power are installed and 91.2 GW with € 50 /tCO_2. In the two cases of wind power investment cost, the gap of carbon prices between LCOE analysis and SIDES simulations is very significant: a difference of € 23 /tCO_2 with wind power investment cost of € 1,200 /kW and a difference of € 30 /tCO_2 with wind power investment cost of € 1,500 /kW.

Finally, this analysis on the sensitivity of the results to the investment cost of wind power confirms that SIDES simulations lead to a carbon price needed for wind power development much higher than the one estimated by LCOE analysis.

III.4.4.b Level of the energy price cap

In the simulations, the energy market is capped at € 3,000 /MWh. This value is the current price cap on EPEX SPOT which applies in France. The price cap influences the level of capacities installed because the peak units should cover their cost during period of electricity outages (scarcity rent). In the reality, setting the price cap is quite challenging: regulators want to ensure security of supply (favourable to high energy price cap) and limit the price for consumers (favourable to a low energy price cap).

With our assumption on the energy price cap (€ 3,000 /MWh), electricity outages occur approximately 10 hours per year. This value is relatively high compare to the acceptable level for consumers (for example, the French objective of electricity of supply is to limit electricity outages to 3 hours per year). In such a situation, real investors could anticipate that regulators would take actions to limit these periods of electricity outages (by increasing the energy price cap or introducing a capacity mechanism). This

Carbon price (€/tCO_2)		50	60	70	80
Case A with price cap of €3,000/MWh	Wind capacity (GW)	0	0	37.7	74.2
	Thermal capacity (GW)	88.3	88.5	83.4	78.9
Case A with price cap of €20,000/MWh	Wind capacity (GW)	0	0.27	32.7	72.6
	Thermal capacity (GW)	93.5	93.3	88.6	84.7

Table III.8: Wind capacity in case A and sensitivity to the energy price cap

aspect is not represented in the modelling. However, another set of simulation was carried out in order to estimate the sensitivity of the results to the price cap. All the simulation parameters are identical to case A except the energy price cap that is fixed to € 20,000 /MWh instead of € 3,000 /MWh.

The results on wind capacity (see table III.8) obtained with an energy price cap of € 20,000 /MWh are quite close to case A. The development of wind power appears approximately for the same range of carbon price. With € 60 /tCO_2, only 0.3 GW of wind power is installed; with a value of € 70, wind capacity reaches 32.7 GW. These two sets of simulations only differ in terms of outages: instead of roughly 10 hours, there is less than one hour of electricity outages per year as a consequence of the higher energy price cap which allows for the development of a larger capacity of peak power plants (this could be observed by the difference in thermal capacities with case A). Finally, these simulations with an alternative value of the price cap show that the main results in terms of wind power deployment are not really affected by this assumption.

III.5 Conclusions

Reduction of CO_2 emissions is one of the main objectives put forward by today's energy policies. Different policy instruments like subsidies to low carbon technologies, emissions standards or carbon price can be used to achieve this objective. Today, both subsidies to Renewable Energy Sources of Electricity (RES-E) (for example Feed-In Tariffs (FITs) or Feed-In Premiums (FIPs)) and carbon price (EU Emissions Trading System (EU-ETS)) are in force in the European Union. In the context of electricity markets which are supposed to organise the long term coordination of decentralised market players on the basis of hourly prices equal to short term marginal costs, this chapter explores the possible development of wind power within an energy-only market without any support scheme. A carbon price is introduced in order to trigger investments in renewable energies. System Dynamics (SD) modelling is employed to simulate evolutions in the generation mix over a 20-year period for different values of carbon price. The results obtained for the different carbon prices allows conclusions of three types to be drawn.

First, results confirm that not only economic competitiveness in terms of Levelised Cost Of Electricity (LCOE), but also profitability against traditional fossil-fuel technologies are necessary for a market-driven development of wind power. Indeed, the study highlights a very significant gap between the carbon price which makes wind power competitive in LCOE analysis and the carbon price which triggers market-driven investments in wind power in the simulations of investments in electricity generation. Market-driven development of wind power only becomes possible if the carbon price is far higher than the threshold given by the analysis of LCOE. In this way, this chapter strongly illustrates that LCOE approach is a poor way of assessing what carbon price would be necessary to achieve substantial market-driven development of wind power. Besides, if we keep the nuclear option open as a low carbon technology, results show that market-driven development of wind power is not possible. In the case of an important existing nuclear capacity, wind power investments require a moratorium on new nuclear development and a sky-rocketing carbon price.

Second, in the case with an initial pure fossil-fuel based system, the results with a carbon price high enough to trigger wind power investments clearly show a gradual saturation of wind power development when the carbon price increases. This effect, also known as "cannibalisation effect", is explained by the decrease in the economic value of wind power

because of its own development. Indeed, each additional MW of wind power participates to decrease electricity prices precisely during hours when wind farms generate electricity, thus further investments in wind power become less profitable for private investors. As a consequence, the wind-weighted average price progressively becomes lower than the time-weighted average price when wind power capacity increases.

Third, the wind power development observed in the simulations causes additional impacts on the functioning of the considered power system. Compared to the case without wind power, a significant capacity of wind power has two main effects on the system: it increases the volume of unserved energy (outage events) and it also increases the volume of electricity spill-overs, occurring when the electricity generated by wind turbines is higher than the electricity demand in real time. In practice, it suggests that storage capacities and flexible capacities would play a key role in the functioning of power systems with high variable RES-E share.

Finally, this case study suggests that the transition to full market integration of on-shore wind power, and more generally variable RES-E, should be gradual and supported by strong political commitments reflected by a high and stable carbon price. Indeed, the assumption of a policy based on a fixed and high carbon price requires strong political commitments that may not arise in reality. Moreover, as shown by IEA and NEA (2007), the level of CO_2 price should be significantly higher to trigger investment in wind power plants if uncertainty on carbon price and risk averse investment behaviours in the electricity markets are taken into account. Thus, as the carbon price emanating from the EU-ETS is likely to remain uncertain in the future despite the envisaged reforms, further developments of the present Simulator of Investment Decisions in the Electricity Sector (SIDES) model will assess possible impacts of uncertain carbon and -fuels prices on the development path of wind power.

To enlarge the scope of this chapter, further works could deal with the potential sensitivity of the results to the types of considered variable RES-E including off-shore wind power or Solar Photovoltaics (PV). In addition, the relationship between the generation profile of a given variable RES-E and the electricity load could also be analysed for example by considering data from different countries which would probably provide various links between variable generation profiles and electricity demand. Besides, in the context of the current debate about security of supply, a number of countries have

implemented (or will implement) a capacity mechanism in addition to the energy market. In this perspective, the analysis of market-driven development of RES-E presented here could be extended to integrate additional revenues from a capacity mechanism.

Chapter IV

Enhancing capacity adequacy of mature power systems

* * *

The functioning of liberalised power markets suffers from several market failures that can result in a low level of security of supply. This chapter analyses how a capacity market mechanism can address security of supply objectives in power systems under energy transition scenario. The addition of a capacity mechanism in a market architecture with price cap is compared to scarcity pricing, for two energy transition scenarios and for different levels of risk aversion of a representative investor.

This chapter starts with an introduction on the importance of enhancing capacity adequacy in most power systems, provided in section IV.1. Then, section IV.2 details the methodology used to assess how a capacity mechanism can enhance the security of supply in power systems under energy transition. Section IV.3 presents and discusses the results obtained for different levels of risk aversion. Finally, section IV.4 concludes and provides policy insights for enhancing the security of supply. This chapter is based on a working paper[1] and on a conference paper[2] which considers risk averse behaviour of investors.

[1]Petitet, M., Finon, D., and Janssen, T., 2016. Ensuring capacity adequacy during energy transition in mature power markets: A social efficiency comparison of scarcity pricing and capacity mechanism. CEEM Working Paper n°20.

[2]Petitet, M., 2016. Effects of risk aversion on investment decisions in electricity generation: What consequences for market design? In Proceedings of the 13th International Conference on the European Energy Market.

Contents of chapter IV

IV.1 Introduction

In the European Union, an important debate has emerged around the issue of capacity adequacy in power markets. The concerns about the short term and long term functioning of power markets are reinforced by the important deployment of variable Renewable Energy Sources of Electricity (RES-E) supported by long term production subsidies (for example Feed-In Tariffs (FITs) or Feed-In Premiums (FIPs)). In the electricity markets textbooks, energy prices in the energy-only market design are supposed to drive investment choices in power generation in order to ensure long-term generation capacity adequacy in parallel with the optimal mix development (see section I.2 of chapter I). Essential conditions for electricity markets sending the right price signals to reach adequate level of capacity are (i) allowing prices to reflect scarcity during demand peaks and (ii) providing that investors trust the long-term price signals conveyed by the day-ahead market.

However, for many reasons ranging from system operator rules during critical periods and operational price caps to the political unacceptability of very high prices, power prices rarely reach the theoretical Value Of Loss Load (VOLL) in practice, leading to a chronic shortage of revenue for plant operators. This so called *missing money* issue is widely developed in the academic literature (Jaffe and Felder, 1996, Hogan, 2005, Joskow and Tirole, 2007, Joskow, 2008, Cramton and Stoft, 2008, Fabra et al., 2011). The proponents of the unfettered energy-only market denounce system operators' operational procedures and the introduction of price caps as the most important barriers to efficient scarcity pricing, whereas scarcity pricing should be an important element in the future market design. To those who point risks of more volatile prices inducing issues of political acceptance or abuse of market power, the authors answer that these risks can be avoided by hedging against volatility while assuming complete markets. The 2015 Communication of the European Commission on market design reforms (European Commission, 2015) develops this position:

> "Allowing wholesale prices to rise when demand peaks or generation is scarce does not necessarily mean that customers are exposed to higher or more volatile prices. Well-functioning longer-term markets will allow suppliers and producers to manage price swings on spot markets – where generators

> effectively can sell insurance to suppliers and consumers against the impact of price swings and also improve the long term investment signals. Market participants, including renewables producers, should be able to hedge against price volatilities and volume risks translating the uncertainties connected to price peaks into planned and secure revenue. This is why it is critical both to allow for price fluctuations in short-term markets and link them to long-term markets."

Given the specificities of power markets, such hedging products are unlikely to emerge due to the misalignment of the interests of investors and suppliers (Chao et al., 2008). Thus, the focus should be put back on the market failures in an energy-only market without price cap. Whereas price peaks constitute a significant share of generators' revenues and thus an important signal for any decision, the frequency and the level of these price peaks are hardly predictable. Under such conditions, it is difficult to anticipate the level of capacity – including peak capacity – that will spontaneously emerge from market players and therefore the occurrence of load shedding and outage situations. In other words, scarcity prices are highly uncertain and intrinsically volatile and, most importantly, there is no guarantee that adequacy standards set at political level will be achieved. The missing money problem is even worse if investors are risk averse, given the risk on revenues during peak periods. Accordingly, as already pointed out in section I.4 of chapter I, the inclusion of a capacity mechanism contributes to improving the social efficiency of electricity markets (Oren, 2005, Joskow, 2008, Cramton and Stoft, 2008, De Vries and Heijnen, 2008, Cramton et al., 2013).

In an original analysis of the market failures in matters of capacity adequacy, Keppler (2014) highlights two imperfections of the energy-only market which justify the transitory adoption of a capacity mechanism: the high social cost of unreliable supply – in particular the cost of unannounced and involuntary supply interruptions – and the asymmetric incentives for agents to invest in peaking units compared to baseload technologies in a situation of inelastic demand and discrete sized generation units. More specifically, the discrete nature of the long term supply function due to the nominal power capacity of each technology, combined with the inelasticity of the demand does not allow for any correct anticipation of rents which could cover fixed costs of new peaking units, in the absence of appropriate hedging products to trigger investment decisions. This invites

to analyse the issue of investment in generation with a discrete representation of plant capacities and behavioural hypothesis of risk aversion.

The issue of capacity adequacy is reinforced by the growing part of intermittent generation from RES-E directly dependent on weather conditions. Indeed, mature electricity markets as the EU electricity markets combined with very active renewables promotion offer a radically different economical context for existing generators and investors who were used to invest in a world of demand growth. Development of RES supported by out-of-market mechanisms further complicate the situation for at least three reasons: (i) on the short term, generation by RES tends to alter the pricing on short-term energy markets and to decrease the revenues of existing and new conventional plants by the so-called "merit order effects" (Sensfuss et al., 2008); (ii) energy prices become more variable between hours and price-risk increases for investors; and (iii) anticipations of future development of RES capacities and their influence on prices related to their production share are uncertain (Nicolosi and Fürsch, 2009). In consequence, energy spot prices do not seem to assume anymore their theoretical long-term coordination function to guarantee capacity adequacy of the system in parallel to the development of an optimal mix. This context affects both new projects in conventional units because of a huge uncertainty on the possibility to recover their fixed costs and existing power plants because of the difficulties to recover operating costs on the short-term as evidenced by a wave of mothballings or closures of recently built gas power plants announced by a number of European electricity producers. At the same time, electricity systems need more back-up capacities to face increasing share of renewables with variable production. Thus, the debate on missing money has evolved towards a new issue: the recovering of operating costs for existing plants besides the traditional issue of recovering fixed costs of new units to trigger investment decisions which is also amplified by the price variability resulting from the high share of variable productions. In this respect, the motivation of introducing a capacity mechanism is reinforced as a solution to complement the market design so that generation adequacy is preserved and enhanced. So, in 2015-2016, several European countries are setting up specific capacity mechanisms and others are considering implementing one, despite the reluctance of the European Commission for which scarcity pricing approach remains the theoretical benchmark solution to trigger new investments[3].

[3]The European Commission develops this idea in its communication on a new energy market design (European Commission, 2015): "an essential condition for electricity markets sending the right price

To inform this debate, this chapter focuses on a capacity mechanism which can be a decentralised obligation assigned to electricity suppliers, similar to the mechanism proposed in France, or a forward capacity market with auctioning by the system operator as some US mechanisms as PJM or New England (Finon and Pignon, 2008). The objective is to analyse how the introduction of this capacity mechanism enhances long-term generation adequacy compared to the energy-only market with or without price cap in the case of mature markets characterised by a stable demand and an increasing share of RES-E, as it is the case in a number of European member-states. To do so, evolution of the electricity market is simulated over several years with a System Dynamics model. By focusing on time evolution, this approach is particularly adapted to study mature markets in which a distinction is made between economic rationale of existing plant retirements and economic decisions for new investments. Moreover, the model integrates both new investments and closure decisions, which constitute a relevant originality to study mature markets prone to RES policy shocks. The second originality of the approach is to compare scarcity pricing to capacity mechanism market designs under different hypothesis of investment behaviours in terms of risk aversion.

The simulations underline how investment and retirement decisions are affected under three different market designs: (i) energy-only market with price cap, (ii) energy-only market with scarcity pricing and (iii) the addition of a capacity market to an energy market with price cap. These three market designs are simulated with two different hypothesis of investors' behaviour: firstly, the study is conducted under risk neutrality and secondly, the study is extended to estimate the effects of taking risk aversion into account. As a consequence of both stable electricity demand due to energy efficiency and increasing renewable share, some thermal units are expected to be decommissioned endogenously.

signals for investment in adequate capacity is to allow prices to reflect scarcity during demand peaks, and for investors to have confidence in this translating into long-term price signals". More recently, the need of high price peaks to reflect scarcity is also mentioned in the conclusions of the Florence Forum of March 2016 (EERF, 2016).

IV.2 Definition of the study

IV.2.1 Methodology

The study is carried out by with the Simulator of Investment Decisions in the Electricity Sector (SIDES) model described in section II.3. For the purpose of this study, the main parameters of the SIDES model are the following:

- New investment decisions are based on the Profitability Index (PI) computed with a discount rate of 8% in accordance with central assumption of DGEMP (2003) and DGEC (2008).
- The representative investor is risk-averse. Results are presented for risk-neutrality and for different levels of risk aversion.

Simulations are conducted for two case studies presented in following subsection IV.2.1.a and for different market architectures detailed in subsection IV.2.1.b.

IV.2.1.a Definition of the two case studies

Two case scenarios are carried out under general assumptions corresponding to the energy transition but with an assumption of forced decommissioning in the second scenario. Energy efficiency efforts are supposed to mitigate consumption growth resulting from macroeconomic evolution, so that electricity consumption remains stable over the time period of this simulation (20 years). At the same time, exogenous wind power development is made possible by support mechanism (for example, Feed-In Tariffs (FITs) or Feed-In Premiums (FIPs)). As a consequence of those two main assumptions, net electricity demand to be supplied by thermal units decreases over time. In a first set of simulations, decommissioning decisions are completely endogenous under the effect of exogenous entry of renewables which jeopardises economic profitability of existing power plants. In a second set of simulations, some closures of coal and nuclear plants are programmed exogenously, which simulates that some units reach the end of their technical life time or that legal rules or political decisions provoke their early closure. The goal is to study the effects of different market designs in terms of social efficiency along these two scenarios.

IV.2.1.b Definition of the three market designs

Three different market designs are tested in each case study. Table IV.1 summarises the key features of the market designs considered. The first market design ("EOM3") corresponds to the current energy-only market, with a price cap of € 3,000/MWh as it is the case on EpexSpot market in the North-Western Europe. The second one ("EOM20") is the theoretical energy-only market with scarcity pricing. In that case, the price reaches the social Value Of Loss Load (VOLL) if electricity generation is not sufficient to serve all electricity demand. In the simulations, this value of loss of load is estimated to be € 20,000/MWh, which is consistent with RTE (2011). Lastly, the third market design ("CM") tested in the simulations corresponds to the addition of a capacity mechanism to an energy market with price cap at € 3,000/MWh. The considered capacity mechanism corresponds to a capacity-wide market without capacity-price cap, which modelling is detailed in section II.3.4 of chapter II.

In practice, implementing a market design supposes to estimate and calibrate its parameters. For regulators, estimating the VOLL can be very challenging. The economic efficiency of a market design can depend on the quality of its parameters' calibration by regulators. In this study, the exact VOLL is supposed to be € 20,000 /MWh in the considered system. Thus, the design EOM20 which is simulated here corresponds to a perfectly designed energy-only market with scarcity pricing as the hourly energy price reaches exactly € 20,000 /MWh when demand exceeds available supply.

Market design	"EOM3" Energy-only market with price cap	"EOM20" Energy-only market with scarcity pricing	"CM" Capacity mechanism
Price cap on the energy market (€/MWh)	3,000	20,000	3,000
Capacity mechanism	No	No	Yes

Table IV.1: Presentation of the three market designs.

IV.2.2 Data on technologies' characteristics, costs and demand forecast

Power plants' characteristics

In the simulations, four thermal generating technologies are considered[4]: combined cycle gas turbines (CCGT), coal-fired power plants (Coal), oil-fired combustion turbines (CT) and nuclear power plants (Nuclear). Technical and cost assumptions which are detailed in table IV.2 are from IEA and NEA (2010) and DGEC (2008). Wind power is included in the simulations in order to represent renewables in a simple way. Its development is fixed exogenously according to the assumptions on energy transition. Because of that, no precise cost data are needed for wind power. In further analysis, the cost associated with wind power deployment to be paid by consumers via a levy is computed under the assumption of a FIT set at € 80 /MWh corresponding to present FIT level common to a number of countries.

	CT	CCGT	Coal	Nuclear
Investment cost (k€/MW)	500	800	1,400	3,910
Annual O&M cost (k€/MW.year)	10	20	30	75
Annualised fixed cost (k€/MW.year)*	57	91	147	391
Power capacity (MW)	175	480	750	1,400
Variable cost (€/MWh)**	162	66	42	10
Forced outage rate (%)	8	5	10	5
Construction time (years)	2	2	4	6
Life time (years)	25	30	40	60

* With a discount factor of 8% (central assumption of DGEMP (2003) and DGEC (2008)).
** The variable cost corresponds to the sum of fuel cost and carbon cost. Gas price is € 10.2 /MMBtu (€ 9.7 /GJ); coal price is € 150 /ton (€ 4.2 /GJ) and oil price is € 88.7 /barrel (€ 15.3 /GJ) according to the assumptions of IEA and NEA (2010). Carbon emission factor is supposed to be 0.35 tCO_2/MWh for CCGT and 0.8 tCO_2/MWh for coal and CT. The carbon price is set to € 6 /tCO_2 (mean value observed on the EU emissions trading system in 2014).

Table IV.2: Economic and technical parameters of generating technologies used in chapter IV.

[4]For sake of simplicity, demand-response is not considered here. However, (Petitet, 2015) considers the effects of different market architectures on investments including demand-response programs.

Demand response programs could be an element of the supply resources in a long term simulation modelling but it is not considered here in order to limit the complexity of the modelling approach, while the flexibility services offered by the peaking units (gas turbines, fuel oil combustion) could be considered as quite similar in terms in flexibility value during the peaking and critical hours. However, load management aspect is taken into account exogenously through the stability of electricity demand. In that sense, only energy reduction is considered while power reduction is not represented in this case study.

Initial generation mix, exogenous wind power entry and exogenous retirements

The initial mix at the beginning of the simulation correspond to the optimal thermal mix obtained by screening curves method (see section I.1.2 of chapter I) while assuming an existing 8 GW of wind power. This initial generation mix is composed of 43 GW of nuclear, 20 GW of coal, 19 GW of CCGT and 18 GW of CT.

The total capacity of the initial generation mix is defined in order to respect 3 hours/year of Loss Of Load Expectation (LOLE) which results from the calculation by the screening curves optimisation method. In this study, the reference reliability criterion defined by regulators (see section I.4 of chapter I) is supposed to be three hours of loss load per year on average. It is noteworthy that this LOLE-norm of 3 hours per year should theoretically be congruent with the level of the VOLL and the annualised fixed cost of the marginal peaking plant to be installed to reach this performance of security of supply, as exposed in the theory of optimal peak pricing (Boiteux, 1949). So, in theory, the loss of load probability times the VOLL should be equal to the annualised fixed cost of the peaking unit. Nevertheless, two additional remarks can be made. Firstly, power plants have typical size of several hundreds of MW which imply that reaching the exact LOLE-norm is very unlikely to happen even in simulations if the model reflects this discrete characteristic. Secondly, this theory is valid in a context of load growth but should be re-examined in the case of a decrease of the net load. Indeed, an economical decision of early retirement refers to the comparison between anticipated net revenues and annual Operations and Maintenance (O&M) cost of the power plant. Because O&M costs are significantly lower than annualised fixed costs, the LOLE with EOM20 is theoretically

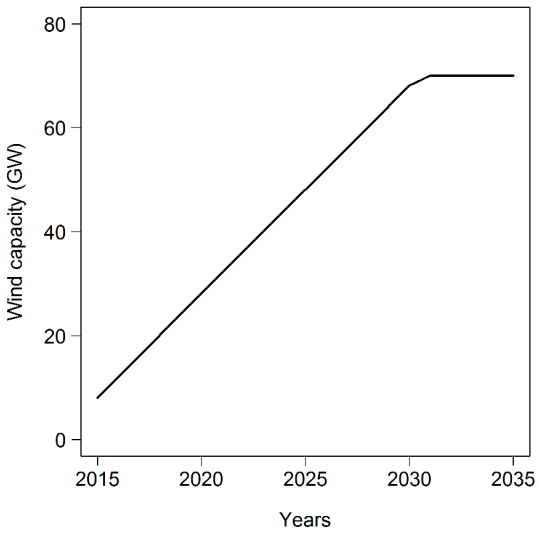


FIGURE IV.1: Exogenous development of wind capacity (assumed for cases 1 and 2).

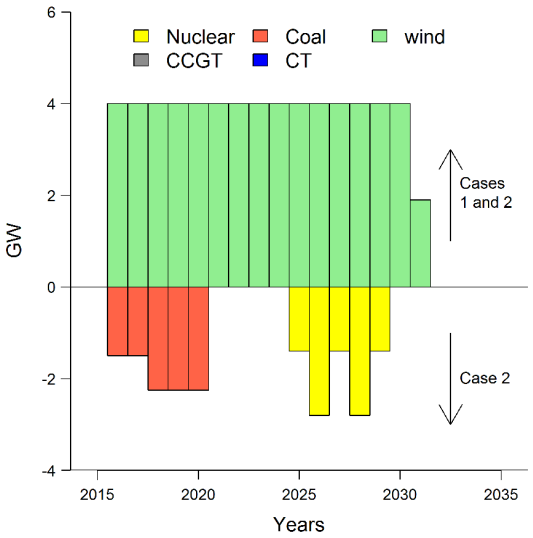


FIGURE IV.2: Respective exogenous entries (for all cases) and closures of power plants (for case 2).

lower than the LOLE-norm of 3hours/per year in the context of endogenous closures due to a decrease of the net load.

With current assumptions on cost parameters, wind power is not economically viable unless the carbon price reaches a very high value (Petitet et al., 2016b) and consequently it should be supported by specific mechanisms (for example, a FIT). As detailed in figure IV.1, wind power installed capacity varies exogenously from 8.1 GW in 2015 to 70 GW at the end of the simulation. In terms of energy share, it represents 3.2% in 2015 and 27.2% at the end of the simulation.

Concerning plant closures, while case 1 does not impose exogenously constraints on thermal power plants, case 2 is set out in coherence with the current debate about nuclear energy and the possible effects of an EU law on polluting plants as for example coal plants. Indeed, in Europe, Germany, Belgium and Switzerland have already planned to progressively phase out nuclear plants. The application of the European directive on large combustion plants (2001/80/EC) could also lead to closures of some large emitting plants. So, in the second set of simulation (case 2), 9.8 GW of coal (13 power plants) are exogenously closed during the period 2015-2020 and 9.8 GW of nuclear (7 power plants) between 2025 and 2030. The details are presented in figure IV.2.

Electricity demand and generation profile of wind turbines

For its decisions, the single representative investor simulated in the SIDES model considers all the weather scenarios available to estimate future profits in the context of annual stable demand over the 20-year period. To do so, it is supposed that the evolution of the total electricity demand is perfectly anticipated by the representative investor, while keeping the meteorological-related risks represented by a distribution of load profiles and correlated wind power production.

The weather sensitivity of electricity demand and wind power generation is taken into account through 11 representative weather scenarios of coherent load demand and wind power generation defined on hourly basis, corresponding to the French case from 2003 to 2013 (according to open-source data available on RTE's website). Appendix E provides more details on the scenarios of electricity demand and load factors of wind power used in this chapter. Based on those data, the capacity obligation to fulfil adequacy requirement of an average of 3 hours/years of loss of load in the considered system is 95.8 GW.

Capacity credit of wind power

For the electricity data used here in, figure IV.3 presents capacity factor of wind power as a function of installed capacity (from 8 GW to 70 GW). It shows that the capacity factor significantly decreases above 30 GW of wind capacity.

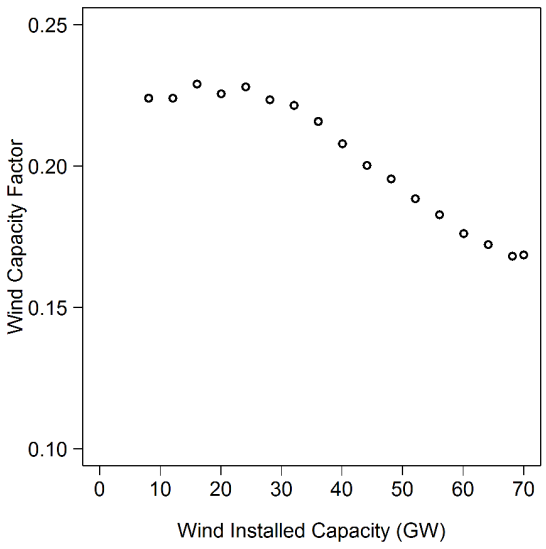


FIGURE IV.3: Wind capacity factor as a function of installed capacity (own calculation)

IV.3 Results and discussion

IV.3.1 Results under risk-neutrality

This section presents the results of simulations carried out with the Simulator of Investment Decisions in the Electricity Sector (SIDES) model for the three variants of market design in the two case scenarios. It details the evolution of the technology mix and different aspects of adequacy issues: performances in terms of loss of load, social efficiency through the addition of production costs and social cost of loss of load, and finally the cost for consumers including the energy component, the eventual capacity component and the cost of renewables' support.

IV.3.1.a Case 1 with endogenous closure of existing power plants

This section presents the results of the case 1 in which the electricity demand remains constant over the period thanks to a restricted economic growth together with efforts on energy efficiency. Wind power development is set exogenously under the assumption that it is supported by a Feed-In Tariff (FIT) of € 80/MWh (which only impacts the calculation of the consumers' electricity bill). Different market design options (EOM3, EOM20, CM implemented under two forms, namely CM3 and CM0.5 described in the newt paragraphs) are analysed in terms of effectiveness to provide capacity adequacy at first, then in terms of social welfare and finally in terms of consumers' electricity bill.

Effectiveness in reaching the adequacy target

In the four market designs tested, some thermal generation capacities are endogenously closed by the representative investor due to the combination of demand stagnation and exogenous wind power entries. The four market designs tested in this risk-neutral case lead to different levels of installed capacity resulting from different decommissioning paths of thermal units which are plotted in figure IV.4.

Compared to energy-only market with price cap at 3,000 €/MWh (EOM3), an additional total thermal capacity of respectively 4.0 GW, 1.5 GW and 6.0 GW remains available at the end of the simulation with EOM20, CM3 and CM0.5 respectively (table IV.3). In

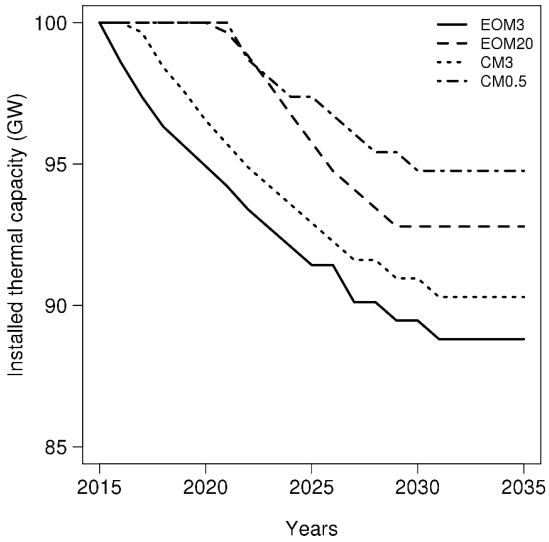


FIGURE IV.4: [Case 1, $\alpha = 0$] Evolution of thermal capacity under the different market designs.

	First year	Last year			
	–	EOM3	EOM20	CM3	CM0.5
Nuclear (GW)	43.0	43.0	43.0	43.0	43.0
Coal (GW)	20.0	20.0	20.0	20.0	20.0
CCGT (GW)	19.0	15.2	15.6	14.2	15.2
CT (GW)	18.0	10.7	14.2	13.1	16.6
Total non RES-E capacity (GW)	100.0	88.8	92.8	90.3	94.8
WT (GW)	8.1	70.0	70.0	70.0	70.0

TABLE IV.3: [Case 1, $\alpha = 0$] Generation mixes (in GW of installed capacity) in the first year and at the end of the simulation for the different market designs.

the results, it appears that some CT and CCGT power plants are closed, while installed nuclear and coal capacities remain unaffected. The fact than CCGT and CT rather than coal or nuclear units are closed is explained by the cost assumptions (Operations and Maintenance (O&M) costs and variable costs). Note that in these simulations, variable generation costs of CCGT and CT are supposed higher than the ones of coal and a fortiori nuclear plants.

To assess the ability of the three market design to guarantee security of supply, the Loss Of Load Expectation (LOLE) was estimated on average over the 11 weather scenarios used in the simulations. Evolution of LOLE over the simulated period is presented in figure IV.5 and table IV.4 for each market design under risk-neutrality. The results

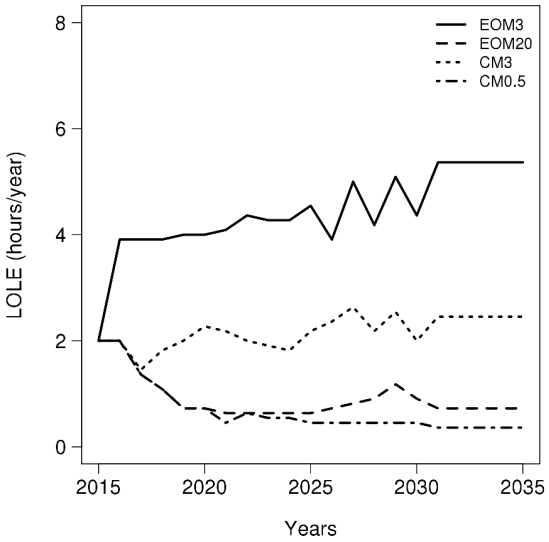


FIGURE IV.5: [Case 1, $\alpha = 0$] Evolution of the LOLE (hours/year) under the different market designs.

underline that EOM3 clearly fails to guarantee the objective of 3 hours of loss load per year even though the system benefits from an inherited over-capacity in this context of a decreasing net demand addressed to conventional units. At the end of the simulation, LOLE is 5.4 h/y with EOM3, 0.7 h/y with EOM20 and 2.5 h/y with CM3. The EOM20 and CM3 meet the LOLE objective of 3 hours per year but even overcome it. Indeed, in case of a decrease in the net demand addressed to thermal units, existing units will be decommissioned only if they don't get back their annual O&M cost from the energy market both on the next year and the five following years. These results highlight that the capacity market (CM3) is the best of the three simulated designs to reach the objective of 3h/y or to be close to it. Of course, the failure of the EOM3 in terms of the LOLE-target of 3h/y could be expected because this design doesn't give enough value to security of supply. On its side, the CM3 design with a capacity mechanism is the only one to internalise the objective of electricity supply, expressed as a LOLE-target, whatever the situation. But, note that the target of 3 h/y is not strictly respected in these simulations with CM because of a combination of different elements: the discrete representation of power plants of typical sizes which makes it difficult to reach the exact adequacy target and the exogenous entry of wind power which further disrupts the system.

In the scarcity pricing market design (EOM20), the profit value of peaking units is generated during critical hours with prices up to the Value Of Loss Load (VOLL) at

Market design	EOM3	EOM20	CM3	CM0.5
LOLE: average (h/year)	4.4	0.9	2.2	0.7
LOLE: last year (h/year)	5.4	0.7	2.5	0.4

TABLE IV.4: [Case 1, $\alpha = 0$] Loss of load expectation (h/year) under the different market designs

€ 20,000 /MWh. In a context of a decrease of the net load, this profit has to be compared to the annual O&M cost of the combustion turbine which is € 10,000 /MW.year. In this context, the ratio between this annual O&M cost and the VOLL explains that the LOLE in EOM20 is theoretically expected to be in the range of 0.5-1 hour per year, which is lower than LOLE-norm of 3 h/y. Finally, this comparison of annual O&M costs (which are significantly different from annualised fixed costs) and the VOLL may raise a question: in a decreasing capacity paradigm, should the LOLE-target of 3h/y be reconsidered? To this end, simulations were also conducted for a CM with a target at 0.5 h/y: the results in terms of LOLE are very close to the ones of EOM20 (see table IV.4).

Comparison of social efficiency of scarcity pricing (EOM20) and capacity mechanism (CM)

This sub-section considers the difference in the respective increases of social welfare between the three reformed market designs EOM20, CM3 and CM0.5, and the reference design EOM3. The social welfare (SW) is defined as the consumers' utility related to electricity consumption (U) from which are subtracted the fixed and variable operating costs of electricity generators (GC) and their annualised investment costs of capacities (AIC):

$$SW = U - GC - AIC \tag{IV.1}$$

Then, the variation of social welfare with respect to EOM3 is defined as the following:

$$\Delta SW(designX) = SW(designX) - SW(EOM3) \tag{IV.2}$$

The variation in operating generation cost (GC) considers both variable generation costs and annual O&M costs of power plants. When new power plants are built during the simulation, it is necessary to include investment costs in the comparison of market

designs by computing annualised investment costs of power plants. The variation in consumers' utility function is defined as the difference of social costs of the non-supplied energy (NSE) which corresponds to the difference of the number of MWh not supplied, multiplied by the VOLL. Here, the VOLL is set at the level of € 20,000/MWh which is identical to the price cap in the scarcity pricing design. Thus, the variation in consumers' utility is:

$$\Delta U(designX) = -(NSE(designX) - NSE(EOM3)) * VOLL \tag{IV.3}$$

The increases of social welfare in the reformed market designs compared to EOM3 are presented in table IV.5. The capacity market with the adequacy target of 3 h/y (CM3) provides a higher social welfare than EOM3 by M€ 69 /year on average over the period. This is less than EOM20 or CM0.5 which stand at an increase of M€ 102/year on average compared to EOM3. Indeed, with EOM20, the price cap on the energy market is set to the VOLL and consequently, the social cost of the non-supplied energy is completely internalised and leads to a LOLE which is different from the ex-ante target of 3h/y. At the end, a contradictory situation is shown here: CM3 is clearly an effective option to reach the targeted LOLE of 3h/y but it does not lead to the best social welfare. This result is a direct consequence of the difference between the adequacy target assigned to the CM3 and the "optimal" adequacy target in this case of a decreasing net demand. This confirms that the optimal capacity adequacy target in terms of LOLE-target should be re-examined in an energy transition context. The new calibration of the capacity market with a target at 0.5 h/y (CM0.5) leads to increase the social welfare compared to EOM3 to a value similar to the one obtained with EOM20. Thus, defining the capacity target of a capacity mechanism is a key issue of its social performance and may depend on the situation of power systems.

The results presented in this section assume risk-neutrality of investors. Nevertheless, differences in risk level is a relevant aspect of market design. To estimate risk levels, revenues of CT were analysed for each simulated year by computing the Relative Standard Deviation (RSD) of the distribution of annual contribution margins (annual gross revenues minus variable generation costs) on weather for each year. The average RSD is 211% with EOM3 whereas it increases to 306% with EOM20 but decreases to 94% with CM3 and 33% with CM0.5. This risk analysis illustrates the strong effect of CM to

compared to EOM3		EOM20	CM3	CM0.5
Variation of consumers' utility (M€/year)	[A]	+141	+86	+152
Variation of generation operating cost* (M€/year)	[B]	+39	+17	+50
Variation of annualised investment cost (M€/year)	[C]	0	0	0
Variation of social welfare (M€/year)	[A-B-C]	**+102**	**+69**	**+102**
	EOM3	EOM20	CM3	CM0.5
Relative standard deviation of CT contribution margins**	211%	306%	94%	33%

* Production cost includes variable costs and annual O&M costs.
** For each simulated year, the relative standard deviation (RSD) of CT annual contribution margins (annual gross revenues minus variable generation costs) is computed over the 11 weather assumptions. Here, the average value of RSD over the 20-year period is shown.

TABLE IV.5: [Case 1, $\alpha = 0$] Comparison of social welfare improvement by implementing scarcity pricing (EOM20) or capacity market (CM3 and CM0.5) (values per year on average) and respective risk levels.

reduce level of risk while EOM20 tends to significantly increase it. Thus, this significant risk level in the various market designs suggests that considering risk aversion in the simulations constitutes a relevant further step to compare these market architectures. This is specifically the goal of following section IV.3.2.

Effects on the electricity bill paid by consumers

In addition to the social welfare evaluation, it is relevant to evaluate the effect of the two reformed market designs (EOM20 and CM) on the consumers' electricity bill compared to the initial design EOM3.

In this calculation, consumers are supposed to have three main components in their electricity bill. To this end, the electricity price for end-consumers (expressed in €/MWh) is composed of the three following components:

- A classical **energy component** which corresponds to the total annual energy revenues to be paid to producers (monetary sum in €) on the spot energy market divided by the total annual electricity consumption (in MWh). In other words, the energy component is the consumption-weighted average energy price of the spot energy market.

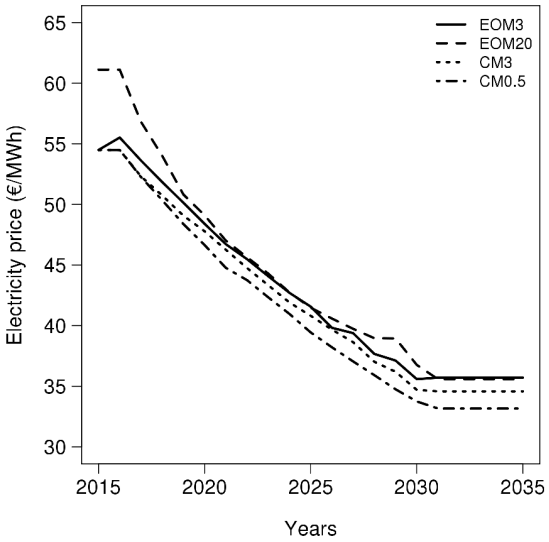


FIGURE IV.6: [Case 1, $\alpha = 0$] Evolution of the energy component of the consumers' bill (the weighted average energy price) under the three market designs.

- A **capacity component**, if necessary (designs CM), which is defined as the generators' total capacity revenues divided by the total electricity sales.
- A **renewable charge** which corresponds to the levy necessary to support wind power development. More specifically, the levy to finance wind power development is obtained as the difference between the revenue of wind power electricity sold on the spot market and a tariff guaranteed by public authorities. The total amount of subventions to wind power is then divided by the annual energy delivered to consumers. In this analysis, the FIT is supposed to be set at € 80/MWh for wind power in line with the current level of FITs common to a number of European countries.

Figure IV.6 presents the energy component evolution over time for each market design. It shows that the energy component decreases over the 20 years as a consequence of the merit order effect of the exogenous wind power development. The energy component is generally higher with EOM20 as a consequence of much higher price cap. The two designs with CM (whatever the LOLE-target) provide lower energy prices than EOM3 because there are less hours during which market price reaches the price cap of € 3,000/MWh (which are also the hours showing loss of load). But, in the case of designs with CM, the electricity bill of end-consumers is made of the energy component plus a capacity component. The evolution of capacity price for the two designs CM3 and CM0.5 is

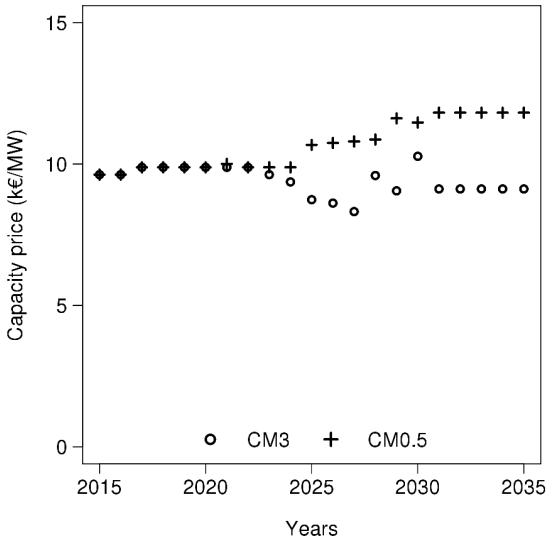


FIGURE IV.7: [Case 1, $\alpha = 0$] Evolution of capacity price (in the market design CM).

shown in figure IV.7. It highlights slight fluctuations which depends on energy revenues of the different plants. Besides, the capacity price obtained with the design CM0.5 is equal to or higher than the capacity price in CM3 because more plants remain on-line with CM0.5, thus less hours of LOLE and less energy revenues for power plants. The average capacity price is k€ 9.4 /MW-year over the 20 years with CM3 and k€ 10.7 /MW-year with CM0.5. On average over the period, this corresponds to an additional capacity component of respectively € 1.8/MWh on the electricity price of end-consumers with CM3 and € 2.2/MWh with CM0.5.

Finally, the average electricity bill for consumers is detailed in table IV.6. These results obtained under risk neutrality show that the electricity bill is slightly lower with EOM3 but this is achieved at the expense of more hours of loss of load. Compared to EOM3, electricity bill of household consumers increases by 1.7% with EOM20, by 1.4% with CM3 and by only 0.05% with CM0.5. These increases of electricity bill with EOM20, CM3 are limited compared to the social benefit of the improvement of the system's capacity adequacy: respectively M€ 102/year for EOM20 and CM0.5, and M€ 69.0/year for CM3(see table IV.5).

The average values presented in table IV.6 hide the evolution of the electricity price for end-consumers that is given in figure IV.8 for each design. Globally, the electricity price for consumers decrease over the simulated period. Indeed, the energy component of the electricity bill decreases because of the change in the generation mix under the effect

	EOM3	EOM20	CM3	CM0.5
Energy(€/MWh)	42.4	43.3	41.5	40.4
Capacity (€/MWh)	–	–	1.8	2.2
Levy to finance wind power (€/MWh)	9.3	9.3	9.2	9.2
Total (€/MWh)	**51.7**	**52.6**	**52.5**	**51.8**

TABLE IV.6: [Case 1, $\alpha = 0$] Electricity bill for consumer on average over the 20 simulated years.

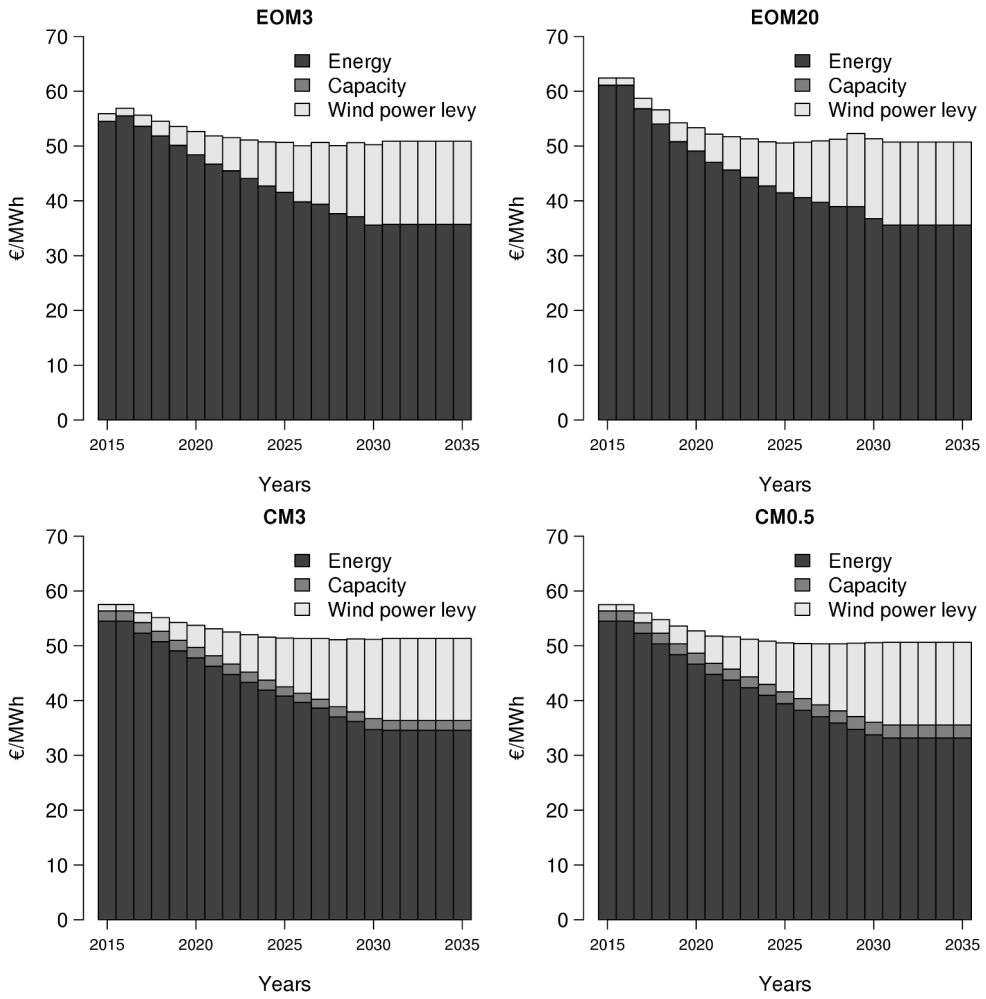


FIGURE IV.8: [Case 1, $\alpha = 0$] Evolution of energy price for end-consumers with the distinction of its three components (energy, capacity and levy to finance wind power).

of exogenous entries of wind power. At the beginning of the simulations, the generated electricity comes predominantly from nuclear (72%) and coal (19%) whereas at the end of the period, it comes from nuclear (63%), wind power (27%) and, to a lesser extent, from coal (9%). As a consequence of this decrease in electricity prices, the levy needed to finance wind power significantly increases from the initial value of € 1.2 /MWh with CM3 and CM0.5 to higher values at the end of the period: € 15.0 /MWh with CM3 and € 15.1 /MWh with CM0.5.

IV.3.1.b Case 2 with exogenous closures of some coal and nuclear plants

This second case study aims to analyse how the simulated electricity system is affected when some closures are imposed exogenously, for example for political reasons. Exogenous wind power development is the same as in the previous case but it is also supposed two "closures shocks": one of 9.8 GW of coal plants (13 units) between 2015 and 2020 and one of 9.8 GW of nuclear plants (7 units) between 2025 and 2030. These two exogenous shocks provoke a need of new conventional capacities besides entries of wind power. In coherence with this need for new investments, the CM market design is implemented for a LOLE-target of 3 hours of loss load per year. This section details the results for the second case scenario under the risk-neutrality assumption and follows the same steps as section IV.3.1.a.

Effectiveness in reaching the adequacy target

The three market designs leads to different levels of installed capacity, as shown in figure IV.9 which presents nuclear and thermal capacities only. Designs EOM20 and CM provide more capacities than EOM3 thanks to the increase in power plants' revenues allowed by the very high price cap in EOM20 and the addition of capacity revenue in CM.

Market design	EOM3	EOM20	CM
LOLE: average (h/year)	9.9	2.2	3.4
LOLE: last year (h/year)	13.3	2.3	2.8

Table IV.7: [Case 2, $\alpha = 0$] Loss of load expectation (h/year) under the three market designs.

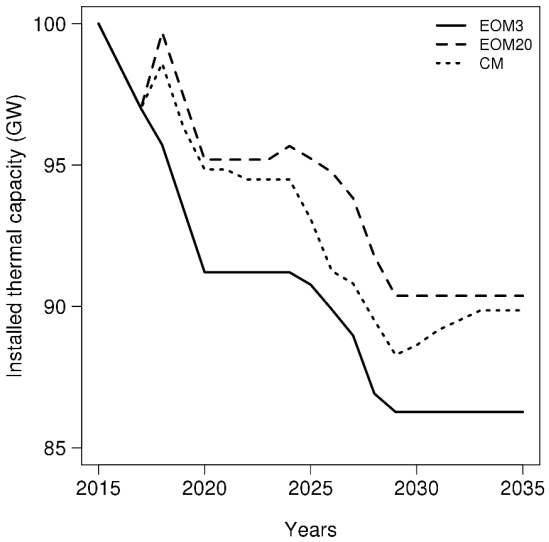


FIGURE IV.9: [Case 2, $\alpha = 0$] Evolution of thermal capacity under the different market designs.

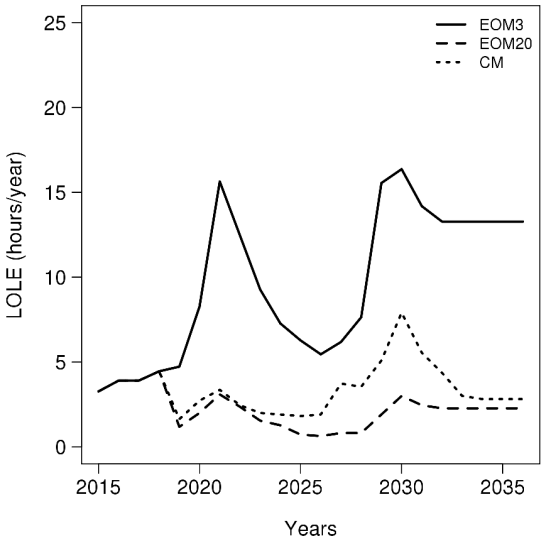


FIGURE IV.10: [Case 2, $\alpha = 0$] Evolution of the loss of load expectation (hours/year) under the different market designs.

	First year	Last year		
	–	EOM3	EOM20	CM
Nuclear (GW)	43.0	33.2	33.2	33.2
Coal (GW)	20.0	11.8	11.0	12.5
CCGT (GW)	19.0	23.3	23.8	24.8
CT (GW)	18.0	18.0	22.4	19.4
Total non RES-E capacity (GW)	100.0	86.3	90.4	89.9
WT (GW)	8.1	70.0	70.0	70.0

TABLE IV.8: [Case 2, $\alpha = 0$] Generation mixes (in GW of installed capacity) in the first year and at the end of simulation for the three market designs.

As a consequence of this increase in physical assets compared to EOM3, the loss of load expectation is logically lower with designs EOM20 and CM, as illustrated in figure IV.10 and detailed in table IV.7. Results underline that EOM20 and CM are effective to ensure the LOLE-target of 3 h/y whereas the LOLE reaches an average value of 9.9 h/y under EOM3 which is not socially acceptable. Besides unacceptable average level of LOLE with EOM3, there are very large variations of the LOLE with this design. The two sharp increases in LOLE during the period 2015-2020 and 2025-2030 correspond to the exogenous closures of coal and nuclear plants respectively in the two periods. Given the price cap of € 3,000 /MWh, energy prices fail to trigger enough investments by increasing revenues. The decrease during the period 2020-2025 is mainly due to exogenous entries of wind power which improve the system's capacity adequacy because capacities of other technologies remain constant. During the period 2025-2030 when exogenous closures of nuclear plants occur, the effects of these closures on the LOLE are compensate neither by the exogenous wind power entries, nor by some endogenous entries of thermal units (mainly CCGT) that were planned during the former period between 2022 and 2025.

In this case scenario 2 in which new investments are needed, these successive closures exacerbate the failure of EOM3 to guarantee system adequacy. Indeed, in the previous case 1 under EOM3, average value of LOLE remains under 6h/y because the system benefits from over-capacity due to the exogenous development of wind power without any exogenous retirement of other units. As a closure's decision only depends on expected net profits compared to annual O&M costs (investment costs are excluded), this over-capacity remains over the simulation period so that LOLE values obtained in EOM3 in case scenario 1 are significantly lower than ones obtained with EOM3 in case 2.

Concerning the differences in average LOLE related to investment incentives given by the three market designs, they are explained by the differences of evolution in thermal capacities in the case scenario 2. Table IV.8 details the generation mixes at the end of the simulation (year 2035) for the three different market designs in this case scenario 2. Compared to EOM3, the increase of capacity with EOM20 mainly corresponds to peaking units (CT) while with CM the additional power plants are more technologically various with CCGT, coal and CT capacities. Then, whereas EOM20 and CM provide quite close results on loss of load expectation, results on technological choices are different. However there is a systematic exceedance of the 3h-norm in the EOM20, on the opposite of the CM market design which brings to a fluctuation over and under the 3-hour standard along the simulation period. This difference is explained by the higher incentives to invest in peaking units (CT) with the market design EOM20 than with the design CM, by the profile of hourly revenues during the small number of critical hours compared to the smoothing revenues allowed by the capacity market with the design CM. When the anticipated LOLE is greater than the target of 3h/y, it is clear that all technologies benefit from higher scarcity rents in EOM20 than in the case of CM. According to the different characteristics of the technologies (costs but also construction time and life time), this can result in different choices even with the same initial mix. Accordingly, the total capacity of coal, CCGT and CT at the end of the 20-year simulation reaches 57.2 GW (with 22.4 GW of CT) with the market design EOM20 and 56.7 GW (with 19.4 GW of CT) with the market design CM.

Comparison of social efficiency of scarcity pricing (EOM20) and capacity mechanism (CM)

The same methodology as in section IV.3.1.a is applied to estimate social welfare effects of scarcity pricing (EOM20) and capacity mechanism (CM) compared to the energy-only market with price cap (EOM3). The welfare comparison is presented in table IV.9. The analysis shows that EOM20 and CM improve the social welfare compared to EOM3.

The consumers' utility logically increases in both reformed designs because the average LOLE is significantly lower with EOM20 and CM than with EOM3. The increase in this consumers' utility is the highest with EOM20 as a consequence of the lowest average LOLE. Average generation costs are lower with CM than with EOM3. The reason lies in

a difference of technology shares because of different revenues between the three different market designs (especially when the anticipated LOLE is high) which lead to different investment decisions according to the profitability index of each technology. As detailed in table IV.8, CM leads to more mid-load units (CCGT and coal) compared to EOM3, resulting in lower variable generation costs, while EOM20 show higher variable costs because it leads to build more peaking units. Here, variation in annualised investment cost is not zero as in the previous case because, as already mentioned, new investments occur to offset exogenous closures. Whereas there are slightly more capacities invested in with EOM20 than with CM, the difference in technological choices (more peaking units with EOM20; more mid-load units in coal and CCGT technologies with CM) results in a lower annualised investment cost with EOM20 than with CM. At the end, the increase in social welfare compared to EOM3 is higher with CM than with EOM20.

The two case scenarios lead to the same results in terms of risk levels for peaking units. As shown in table IV.9, the RSD of CT annual contribution margins increases with EOM20 and decreases with CM compared to EOM3. This confirms that compared to EOM20, CM has a strong advantage in terms of risk reduction for investors.

Effects on the electricity bill paid by consumers

compared to EOM3		EOM20	CM
Variation of consumers' utility (M€/year)	[A]	+350	+297
Variation of generation operating cost* (M€/year)	[B]	+51	-83
Variation of annualised investment cost (M€/year)	[C]	+190	+258
Variation of social welfare (M€/year)	[A-B-C]	**+109**	**+122**
	EOM3	EOM20	CM
Relative standard deviation of CT contribution margins**	171%	275%	70%

* Production cost includes variable costs and annual O&M costs.
** For each simulated year, the relative standard deviation (RSD) of CT annual contribution margins (annual gross revenues minus variable generation costs) is computed over the 11 weather assumptions. Here, the average value of RSD over the 20-year period is shown.

TABLE IV.9: [Case 2, $\alpha = 0$] Comparison of social welfare improvement by implementing scarcity pricing (EOM20) or capacity market (CM) (values per year on average) and respective risk levels, in a situation where new investments by the market are expected.

Regarding the electricity bill paid by consumers computed with the same method as previously exposed, the analysis considers separately the energy component, the capacity component and the charge added to finance the over-cost of wind power MWhs.

The change of energy prices, which are much more variable than in case 1, is related to the exogenous changes in generation mix with the successive sequences of closures of coal and nuclear plants, which imply strong variations in technology shares.

Figure IV.11 presents the energy component paid by consumers defined as the weighted average value of hourly energy prices. It shows that this energy component is roughly the same with EOM3 and EOM20, except at the beginning of the period when the electricity mix evolves differently depending on the market design.

The addition of a capacity market (design CM) significantly reduces electricity prices on the energy market over the period. This is achieved through changes in generation mix towards less peaking units and more mid-load power plants as highlighted above. But, with market design CM, consumers also have to pay a capacity component (as detailed above).

Figure IV.12 presents the evolution of capacity price over the period, expressed in k€/MW. It shows that the annual capacity price (computed without price cap on the capacity market) varies between 7.6 and 61.8 k€/MW. Compared to case 1, capacity

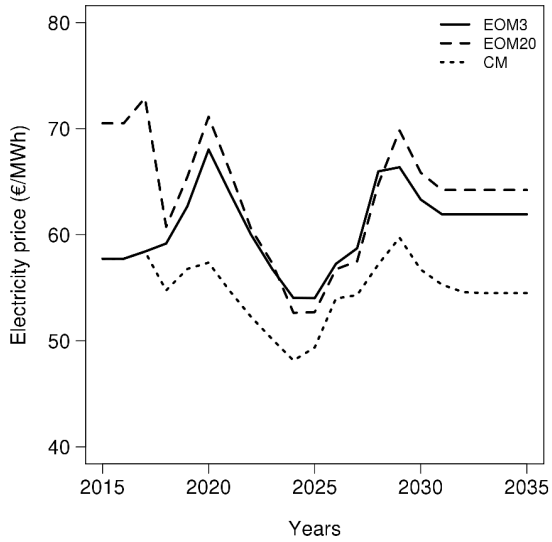


FIGURE IV.11: [Case 2, $\alpha = 0$] Evolution of energy component for consumers (weighted average energy prices; capacity component and renewables charge excluded) under the three market designs.

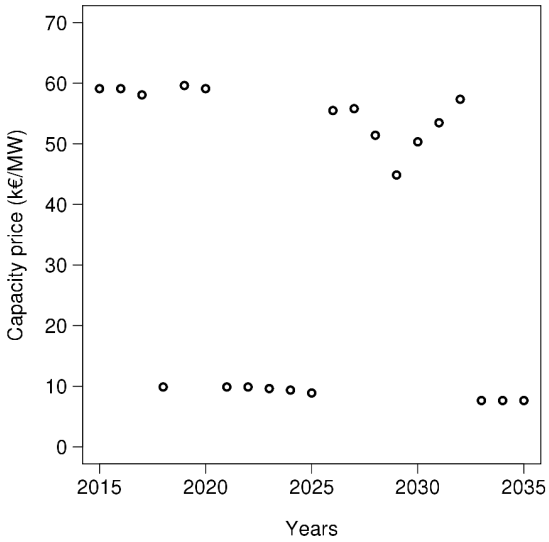


FIGURE IV.12: [Case 2, $\alpha = 0$] Evolution of capacity price in the market design CM.

	EOM3	EOM20	CM
Energy(€/MWh)	60.8	63.3	54.7
Capacity (€/MWh)	–	–	6.6
Levy to finance wind power (€/MWh)	6.7	6.6	5.8
Total (€/MWh)	**67.5**	**69.9**	**67.2**

TABLE IV.10: [Case 2, $\alpha = 0$] Electricity bill for consumer on average over the 20 simulated years

price reaches higher values and is much more variable. This variability is a consequence of the need of new investments in case 2 while in case 1, the results show no new investment but some endogenous closures of capacities in the three market designs. Expressed in €per MWh consumed, the capacity component in the design CM varies between € 1.5 and € 11.6 /MWh to be added to electricity price, with an average value of € 6.6/MWh on the simulation period.

Table IV.10 summarises the situation for consumers presenting both energy and capacity components of their electricity bill on average over the simulated period 2015-2035. These results obtained under risk neutrality show that the capacity component in the design CM is offset by the decrease in energy prices so that in the end, electricity bill is roughly equal with CM and EOM3. This makes the total of energy and capacity components close to the energy component in EOM3 and EOM20 (€ 61.3/MWh with

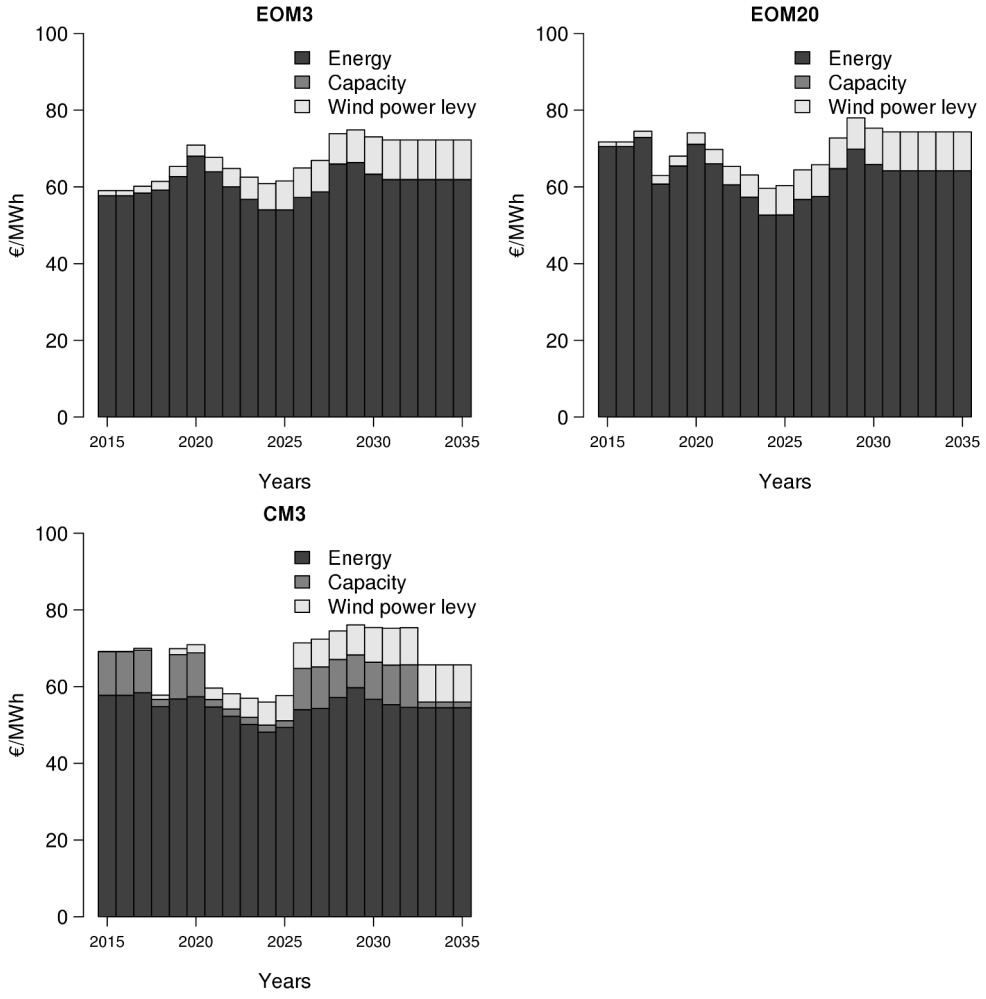


FIGURE IV.13: [Case 2, $\alpha = 0$] Evolution of energy price for end-consumers with the distinction of its three components (energy, capacity and levy to finance wind power).

the design CM compared to € 60.8/MWh with EOM3 and € 63.3/MWh with EOM20, see table IV.10).

On the contrary, the electricity bill is slightly higher with EOM20 compared to EOM3 (+6.1%). Hence, in this scenario case, the capacity market (CM) is particularly efficient because it significantly reduces the LOLE compared to EOM3 but without imposing an increase in electricity bill, while with EOM20 the improvement of capacity adequacy is obtained together with an slight increase of the price paid by consumers of around € 2.4/MWh on average.

(in M€/ year on average)	Case scenario 1	Case scenario 2
EOM20	102	109
CM	[69 ; 102]*	122

* The result depends on the calibration of the capacity market.

Table IV.11: Comparison of social welfare improvement of scarcity pricing and capacity mechanism between case scenarios 1 and 2 (in M€/year on average), under risk-neutrality.

IV.3.1.c Comparison of market designs and case-scenario policies

In the two cases presented above, the energy-only market with the price cap set at € 3,000/MWh (EOM3) clearly fails to maintain an acceptable capacity adequacy even in case of a decrease of the net demand addressed to conventional units (case 1). In each case, the capacity market (CM3) is the closest to the LOLE-target of 3h/y.

However, in terms of social welfare under risk-neutrality, the two case-scenarios show contradictory results (see table IV.11): capacity market is the best option in terms of social welfare in the scenario case 2 whereas it depends on the calibration of the capacity market in case 1. Indeed, CM presents an increase in social welfare (M€ 122 /year) which is higher than with EOM20 (M€ 109 /year) in case 2. In case 1, a social welfare increase in the range of M€ 69-102 /year is obtained for CM (depending on its calibration) instead of M€ 102 /year for EOM20. These figures can be given some context by comparing them to typical dimensions of the studied power system. The annual average energy revenue of producers selling all their electricity on the spot market is € 21.2 billion in case 1 and € 30.0 billion in case 2. Thus, in case 1 with endogenous closures, the increase of social welfare provided by EOM20 or CM0.5 corresponds to 0.5% of the average annual energy revenue. In case 2 with exogenous closures of some coal and nuclear plants, the increase of social welfare under EOM20 or CM corresponds to almost 0.4% of the average annual energy revenue. Relative to the total electricity demand, these increases in social welfare represent nearly €0.2/MWh, computed as the ratio between the annual social welfare increase and the annual electricity demand. Besides, the increase in social welfare obtained with the design CM compared to the reference EOM3 is significant as regards European projects already implemented. For example, the annual increase in social welfare from the flow-based market coupling in central-western Europe is estimated to roughly M€ 100 (CWE FB MC Project, 2014).

	Case scenario 1	Case scenario 2
EOM3	211%	171%
EOM20	306%	275%
CM	[33% ; 94%]*	70%

* The result depends on the calibration of the capacity market.

TABLE IV.12: Comparison of risk level for CT through the average relative standard deviation of CT annual contribution margin for the three market designs and the two case scenarios.

Concerning the capacity target's definition, the fact that CM3 continues to target 3 hour of loss load per year in case 1 with endogenous closures while this lead to a lower improvement of social welfare than EOM20 sheds light on the difficulty to define an optimal capacity target in case of a decreasing capacity paradigm: this is a question that needs to be addressed. The differences between the two cases are due to the highest need of generation investments, given exogenous closures in case 2. CM brings a sequence of more smoothed revenues, which allows for a more efficient adaptation of the fleet of generation units than with EOM20.

This analysis is completed by an estimation a risk level (presented in table IV.12) which is also a key feature of market design. The two case scenarios highlight strong differences in terms of risk level for CT units. In this risk-neutral case, the simulations outputs were analysed in order to estimate the risk level of CT net revenues. Compared to EOM3, the two cases show that EOM20 increases the risk level for peaking units whereas CM significantly decreases it. This suggests that taking risk of private investors into account in their investment decisions could bring further insights on the comparison of the different market designs. The analysis with risk aversion is presented in section IV.3.2 of this chapter.

Besides, the two cases presented above allow for the comparison of policies of endogenous closures of plants or political closures to highlight their effects on the consumers' bill. The comparison is made between the case scenario 1 with only endogenous closures and the case scenario 2 with exogenous closures. It shows that the total bill paid by consumers in case 2 is higher by 31% on average over the three market designs than the one in case 1. This significant difference is explained by the exogenous closures of some coal and nuclear capacities in case 2, which impose to re-invest in conventional technologies despite the exogenous entry of wind power.

IV.3.2 Effect of risk aversion

IV.3.2.a Case 1 with endogenous closures of existing power plants

Effect of risk aversion in an energy-only market with price cap

When risk aversion increases, the generation mix is affected both in terms of total capacity and in technologies' share. In this section, only the results with the energy-only market with price cap set at € 3,000/MWh (design EOM3) are presented.

As illustrated in figure IV.14, the total thermal capacity decreases in time as a consequence of stable electricity demand and exogenous entry of wind power. The level of endogenous retirement of thermal plants is clearly affected by the coefficient of risk aversion defined in the exponential utility function. In the case of risk neutrality ($\alpha = 0$), 11.2 GW of thermal plants are closed. In case of high risk aversion ($\alpha = 3$), the capacity adequacy of the system is significantly worse and 12.7 GW are decommissioned.

The endogenous closures observed in these simulations with an energy-only market with price cap at € 3,000 /MWh concern combined cycle gas turbines (CCGT) and oil-fired combustion turbines (CT) while the capacities of nuclear and coal remain constant over the 20-year period. In the case of risk neutrality ($\alpha = 0$), 3.8 GW of CCGT and 7.4 GW of CT are closed. In case of high risk aversion ($\alpha = 3$), 4.8 GW of CCGT and 7.9 GW of CT are closed.

As a consequence of the difference of generation mix, capacity adequacy differs according to the level of risk aversion. To evaluate capacity adequacy, a common indicator is the LOLE which corresponds to the number of hours during which the installed generating capacity is not sufficient to meet the electricity demand. The LOLE is computed on average over the 11 weather scenarios of the considered year. With EOM3, the results show that the LOLE clearly increases when the level of risk aversion increases, from 4.4 h/y on average over the 20 years (5.4 h/y for the last simulated year) without risk aversion to 13.3 h/y on average (10.3 h/y for the last simulated year) with the highest risk aversion tested here ($\alpha = 3$).

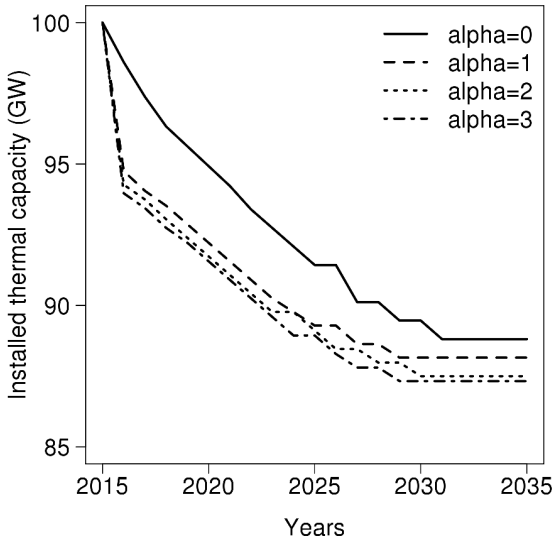


FIGURE IV.14: [Case 1] Evolution of total thermal capacity under design EOM3 for different levels of risk aversion

Therefore, it is clear that the energy-only market with a price cap set at € 3,000 /MWh fails to maintain an acceptable level of capacity adequacy even in the case of an energy transition characterised by a stable electricity consumption and significant entry of renewables.

Comparison of market designs under the assumption of risk aversion

This subsection presents the simulations conducted in case 1 with endogenous closures of power plants, for the three market designs presented in table IV.1 and for different levels of risk aversion.

Globally, the results follow the same pattern of those already presented for EOM3. When risk aversion increases, the installed capacity is reduced and the capacity adequacy evaluated by the LOLE is worse. The values of LOLE obtained for each simulation (on average on the period and at the end of the simulation) are presented in table IV.13. As in the design EOM3, the LOLE obtained with EOM20 is significantly sensitive to the level of risk aversion: it increases from 0.9 h/y on average under risk neutrality to 3.6 h/y with the highest level of risk aversion ($\alpha = 3$). On the contrary, the LOLE remains globally the same with CM3 or CM0.5 whatever the level of risk aversion.

		EOM3	EOM20	CM3	CM0.5
$\alpha = 0$	LOLE average	4.4	0.9	2.2	0.7
	LOLE last year	5.4	0.7	2.5	0.4
$\alpha = 1$	LOLE average	10.0	2.4	2.6	0.9
	LOLE last year	7.1	1.6	2.7	0.5
$\alpha = 2$	LOLE average	12.1	3.3	2.5	0.8
	LOLE last year	9.6	2.3	2.8	0.5
$\alpha = 3$	LOLE average	13.3	3.6	2.4	0.7
	LOLE last year	10.3	2.3	2.4	0.5

Table IV.13: [Case 1] Loss of Load Expectation (hours/year) on average over the simulation and at the end of the simulation, for the four market designs EOM3, EOM20 and CM3 and CM0.5, with different levels of risk aversion

	EOM3	EOM20	CM3	CM0.5
$\alpha = 0$	0.0	102.3	69.0	101.8
$\alpha = 1$	-223.7	61.9	55.5	99.9
$\alpha = 2$	-317.2	31.9	48.9	99.6
$\alpha = 3$	-381.8	17.2	49.7	100.0

Table IV.14: [Case 1] Variation of social welfare (in M€/year on average over the period) compared to the reference risk-neutral case EOM3

Thus, the results show that the capacity mechanism (CM3 or CM0.5) is significantly less sensitive to the level of risk aversion than EOM3 and EOM20. This is explained by the fact that this capacity mechanism is quantity-based and allows producers to receive a capacity remuneration that is fitted to their risk aversion because the clearing price depends on their bids. On the contrary, with an energy-only market, whatever the price cap, the remuneration of the power plants depends only on electricity demand and variable costs of generation units and thus the revenues do not depend on the level of risk aversion.

A comparison of social welfare is conducted with the same methodology as presented above. The analysis of social welfare is presented in figure IV.15 and detailed in table IV.14. It shows that the social welfare of EOM3 significantly decreases when the risk aversion increases. The reformed market EOM20 and CM improve the social welfare compared to EOM3 but their sensitivity to the risk aversion coefficient is not the same: CM is clearly the less sensitive to the level of risk aversion. In that sense, the social welfare obtained with CM is not very dependent on the assumption on the level of risk

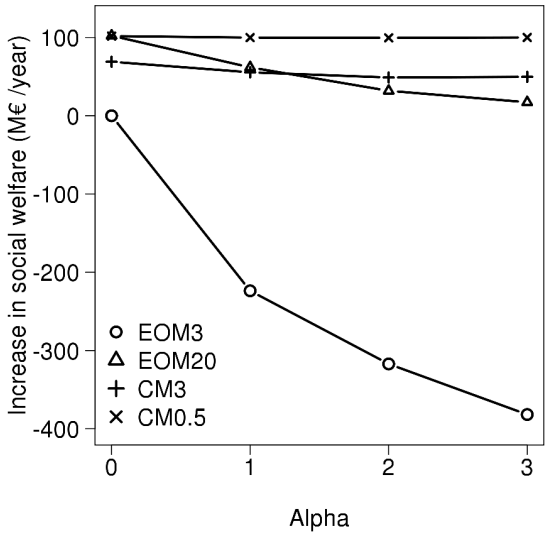


FIGURE IV.15: [Case 1] Variation of social welfare compared to the design EOM3 with no risk aversion ($\alpha = 0$)

aversion while this assumption significantly affects the results of the two other designs EOM3 and EOM20.

Finally, this case study highlights that taking risk aversion into account can significantly change the conclusion of a comparison of market designs and thus it should be taken into account when comparing various market designs. The results presented here clearly highlight that CM is far less influenced by the level of risk aversion than energy-only designs (EOM3 or EOM20).

IV.3.2.b Case 2 with exogenous closures of some coal and nuclear plants

This second case study aims to analyse how the simulated electricity system is affected when some closures are imposed exogenously, for example for political reasons. Exogenous wind power development is the same as in the previous case but it is also supposed two "closures shocks": one of 9.8 GW of coal plants (13 units) between 2015 and 2020 and one of 9.8 GW of nuclear plants (7 units) between 2025 and 2030. Despite the large development of wind power, these two exogenous shocks provoke a need of new conventional capacities to maintain the capacity adequacy of the considered system, which explains that the well-designed capacity market (noted CM) has a LOLE-target of 3 hours/year.

Under the risk-neutrality assumption, the results presented in section IV.3.1.b highlight that a capacity market enhance the situation compared to the energy-only market with price cap, in terms of capacity adequacy and social welfare while decreasing the variability of peaking units' revenues. This section details the results for this second case scenario under different levels of risk aversion.

Concerning the total installed capacity, the results confirm that it decreases when the level of risk aversion increases under all considered market designs, but comparatively less than in the first case in which there is no exogenous closures of coal and nuclear plants. To illustrate this effect on the benchmark design EOM3, the total installed thermal capacity at the end of the simulation reaches 86.3 GW under risk-neutrality and it slightly decreases to 85.6 GW with the highest tested level of risk aversion ($\alpha = 3$) which is explains by a difference of 0.7 GW of CT. Regarding the technological choice of new investments, the results with risk aversion confirm that with the capacity market (CM), there are less investments in peaking units (-3.0 GW with $\alpha = 3$) than with EOM20, but there are more investments in CCGT (+1.0 GW with $\alpha = 3$) and coal-fired power plants (+1.5 GW with $\alpha = 3$) than with EOM20.

Table IV.15 presents the results in terms of capacity adequacy. Whatever the level of risk aversion, the benchmark market design EOM3 fails to guarantee an acceptable security of supply: the LOLE reaches 13.3 hours/year at the end of the simulation without risk aversion and increases to 16.3 hours/year at the end of the simulation with the highest tested level of risk aversion ($\alpha = 3$). However, the two reformed designs EOM20 and CM enhance the situation towards socially acceptable capacity adequacy. An increase of risk aversion level is detrimental to the capacity adequacy because there are less investments in power plants during the simulation period. This effect is particularly obvious with EOM3 and to a lesser extent with EOM20 whereas CM is roughly insensible to the level of risk aversion as already noted in case 1 (see IV.3.2.a).

The increase of social welfare compared to the reference case [EOM3; $\alpha = 0$] is obtained by the same methodology as the one described in section IV.3.1.a. The variations of social welfare (in relative values) are presented in table IV.16 and illustrated in figure IV.16. These results highlight a decrease of the social welfare when the risk aversion increases. This effect is significant for EOM3 and to a lesser extent for EOM20. On the

		EOM3	EOM20	CM
$\alpha = 0$	LOLE average	9.9	2.2	3.4
	LOLE last year	13.3	2.3	2.8
$\alpha = 1$	LOLE average	10.6	2.2	3.1
	LOLE last year	13.3	2.0	2.7
$\alpha = 2$	LOLE average	11.6	2.4	3.2
	LOLE last year	16.1	2.0	2.8
$\alpha = 3$	LOLE average	12.2	3.3	3.2
	LOLE last year	16.3	2.3	2.8

Table IV.15: [Case 2] Loss of Load Expectation (hours/year) on average over the simulation and at the end of the simulation, for the three market designs EOM3, EOM20 and CM, with different levels of risk aversion.

	EOM3	EOM20	CM
$\alpha = 0$	0.0	108.8	121.8
$\alpha = 1$	-28.3	93.3	107.0
$\alpha = 2$	-73.6	73.3	106.4
$\alpha = 3$	-143.2	-74.3	106.5

Table IV.16: [Case 2] Variation of social welfare (in M€/year on average over the period) compared to the reference risk-neutral case EOM3.

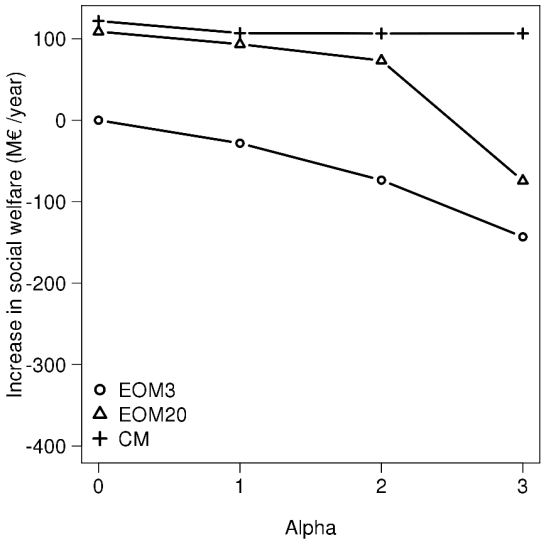


Figure IV.16: [Case 2] Variation of social welfare compared to the design EOM3 with no risk aversion ($\alpha = 0$).

contrary, the capacity market (CM) provides a social welfare which is more robust to the level of risk aversion.

The effect of risk aversion analysed in this second case study confirms the conclusions drawn in the first case study: the comparison between market designs is highly sensitive to the level of risk aversion and the capacity market is far less influenced by the level of risk aversion than energy-only designs (EOM3 or EOM20).

IV.4 Conclusions

This chapter focuses on capacity mechanism in a context of energy transition with (i) demand stagnation thanks to efforts in energy efficiency and (ii) exogenous penetration of variable renewables. The Simulator of Investment Decisions in the Electricity Sector (SIDES) was used to simulate the investment and retirement decisions and the evolution of electricity mix over twenty years under two different case scenarios. The first case simply corresponds to the above-mentioned situation. In the second case, some coal and nuclear power plants are closed exogenously in order to estimate how the system can react to such significant "closures shocks" which could be a result of environmental and climate policies or power plants reaching the end of their operational life-cycle. In each case, three different market designs are tested: the benchmark energy-only market with a price cap of € 3,000/MWh as it is the case on EpexSpot market in the North-Western Europe ("EOM3"); a reformed energy market with scarcity pricing ("EOM20") and a capped energy market with an additional capacity mechanism ("CM"). In each case, the results are analysed first for a risk neutral investor and then for different level of risk aversion.

Case 1 with endogenous closures of existing power plants

In this first case, the net electricity demand to be served by conventional non-renewable technologies decreases over the simulated period under the combined effect of energy efficiency and exogenous development of wind power. Thus, endogenous closures of some existing power plants are observed in the simulations.

Three types of conclusion are drawn in the risk neutral approaches. First, the energy-only with price cap (EOM3) is not sufficient to maintain an acceptable level of Loss Of Load Expectation (LOLE) because of massive decommissioning. In this base case, the LOLE reaches 4.4 h/y in 2035 on average over the period studied. The energy-only with scarcity pricing model (EOM20) and the capacity market (CM3 or CM0.5) significantly enhance the security of supply compared to EOM3 but not in the same magnitude. If the capacity market appears to be the best option to internalise the objective of security of supply expressed as a specified number of loss of load expectation (here, set to 3 h/y or 0.5 h/y), its economic performance depends on the definition of the capacity target.

In particular, the well-designed design CM0.5 with a LOLE-target of 0.5 h/y leads to the same performance than the well-designed scarcity pricing in terms of capacity adequacy. Second, the tests show that compared to a capped energy-only market (EOM3), the social welfare is enhanced with an energy-only market with scarcity pricing (EOM20) or with a capped energy-only market plus a capacity mechanism (CM). In this case of decrease of the net demand addressed to conventional units in which no new investments are needed, the well-designed CM with an adapted LOLE target is as efficient as a well-designed scarcity pricing design. Last but not least, the analysis indicates that the level of risk for peaking units widely varies from a market design to another. More specifically, the level of risk measured through the relative standard deviation of CT revenues is reduced with CM3 or CM0.5 compared to EOM3 while it is significantly increased with EOM20. In other words, the scarcity pricing creates a riskier environment for investors than the capacity market. So, when risk aversion is taken into account in the investment decisions, the effects of the different market designs observed in the simulation are thus different.

The case study with risk aversion completes the analysis by qualifying how the level of risk aversion affects the hierarchy of market designs and decisions of early retirements of conventional plants. First, the results show that the energy-only markets with price cap or without price cap (scarcity pricing) are very sensitive to the level of risk aversion. Second, when comparing different market designs in terms of social efficiency, the relative ranking is affected by the level of risk aversion. Thus, it is important to consider risk aversion when policy makers have to decide between scarcity pricing and capacity mechanisms. Third, a well-designed capacity market, in particular as regards the definition of the capacity target, appears to be the best choice whatever the level of risk aversion ("least regret" choice). This market design is not really sensitive to the level of risk aversion both in terms of loss of load expectation and social welfare. This is a strong advantage for policy makers as its effectiveness would remain the same whatever the degree of risk aversion of the investors.

Case 2 with exogenous closures of some coal and nuclear plants

In this second case, the exogenous development of wind power is not sufficient to offset the exogenous closures of some coal and nuclear power plants. Thus, new endogenous

investments are observed in the simulations. The results obtained in this second case scenario confirm the conclusions already drawn from the first one. In particular, the design EOM3 is not sufficient to trigger enough new investments to maintain a socially acceptable capacity adequacy whereas the reformed market designs EOM20 or CM significantly enhance the situation. More specifically, the design CM provides a higher social welfare than the ones under EOM3 and EOM20 whatever the level of risk aversion. Similarly to the first case scenario, the higher sensitivity of energy-only design to the level of risk aversion is confirmed in this second case scenario.

General conclusions and further considerations

The efficiency and the comparison of different market designs can be influenced by different factors among which the considered case scenario (that is to say the general context and exogenous constraints) and the risk aversion level of private investors. Based on the analysis of two different energy transition scenarios, this chapter draws two main conclusions.

First, the addition of a well-designed capacity mechanism (design CM) appears to be the best option among the studied designs. Indeed, whatever the level of risk aversion, the design CM guarantee a socially acceptable LOLE and thus, it significantly increases the social welfare compared to EOM3. For its part, the design EOM20 enhances the situation compared to EOM3 but it is less efficient than a well-designed CM in terms of social welfare, particularly when the level of risk aversion is high.

Secondly, the comparison of the tested market designs is affected by the level of risk aversion, in terms in ranking of the designs in case 1 and in terms of quantitative comparison in case 2. The average increase of social welfare under the reformed designs compared to the benchmark EOM3 depends on the considered case scenarios. More specifically, the design CM provides an average annual social welfare increase compared to EOM3 in the range of [M€ 100 ; M€ 500] in case 1 depending on the level of risk aversion and in the range of [M€ 100 ; M€ 250] in case 2. These figures can be given some context by comparing them to the average annual energy revenues of producers in the benchmark design EOM3: this corresponds to [0,4% ; 2,2%] of annual energy revenues in case 1 and to [0,3% ; 0,8%] in case 2. Besides, this effect on the social welfare is substantial compared to implemented project as for example the flow-based market

coupling in central-western Europe which increases the social welfare by approximately M€ 100 /year (CWE FB MC Project, 2014).

To complete these results, further work should cover the analysis of different simulation scenarios for demand and technologies considered. Besides, analysing the sensitivity of the various market designs to the quality of their calibration also constitutes an insightful further research topic. Indeed, for both energy-only market with scarcity pricing and the addition of a capacity mechanism to an energy market with price cap, the calibration of the price cap in the first market architecture or the calibration of the LOLE target in the latter market architecture remains a challenging step to be done by regulators. Estimating the consequence (as regards capacity adequacy and social welfare) of an error in the calibration of these market designs could bring practical reasons in the choice of a market design.

General conclusion

In liberalised power systems, power markets theoretically ensure the long-term coordination of investments in the various generating technologies in order to guarantee security of supply, sustainability and competitiveness. In a reference energy-only market, this long-term coordination relies on the ability of marginal pricing in power markets to provide an adequate price-signal for private investors. However, in practice, questions have been raised about its ability to trigger investments in Low-Carbon Technologies (LCT) including in particular Renewable Energy Sources of Electricity (RES-E), and about its ability to ensure capacity adequacy with respect to reliability standards defined by regulators.

This dissertation focuses on the long-term coordination function of power markets which has received relatively less attention when compared to the short-term one since the liberalisation reforms (Joskow, 1997). More specifically, this long-term coordination function raises two issues: (i) investments in LCT including in particular RES-E characterised by high fixed costs and low or zero variable costs, hence the complexity of investment decisions in electricity markets with marginal pricing, and (ii) capacity adequacy to guarantee supply reliability in any given situation in the context of mature electricity systems disrupted by the development of RES-E capacities with variable production.

The **first chapter** analyses the long-term coordination function of investments by electricity markets and highlights the importance of the two research topics addressed in this dissertation. Because of limited storage capacities and physical laws to be respected in real-time, electricity product is peculiar compared to other commodities. More specifically, the analysis of electricity demand on the one hand and electricity supply on the other hand leads to distinguish electricity products along five dimensions: (i) the nature of the product which can be a quantity of energy but also the guarantee of an available

power capacity during a given period to ensure the security of supply, (ii) the specified quantity to be delivered, (iii) the specified time of delivery, (iv) the specified place of generators and consumers and (v) the lead-time between the time of the contract and the time of delivery. Power markets organised within various time spans are structured by these different dimensions in order to guarantee the physical laws of electricity. Besides, this combination of power markets also aims at ensuring the coordination functions of liberalised power system. In particular, the day-ahead market is supposed to provide long-term signals for investments in order to ensure a correct level of installed capacity and a technology mix compatible with environmental goals as formalised in public policies. Additional environmental and climate policies are generally added to cope with this second aspect of providing a relevant technology mix.

Regarding long-term investment signal, several market and regulatory failures of the energy-only market are identified in the literature among which the most frequently cited are (i) the existence of explicit or implicit price caps that prevent energy prices to reach the high values needed to ensure capacity adequacy, (ii) risk aversion and imperfect information which can limit the willingness of investors to build peaking units or low-carbon technologies and (iii) the lumpiness of investment decisions which further complicates the reach of the theoretically long-term equilibrium.

In this context, current debates on power systems particularly focus on suggesting solutions to enhance capacity adequacy while allowing the development of LCTs including RES-E in relation to the environmental objectives (Finon and Roques, 2013). Concerning investments in LCTs including RES-E, the analysis shows that specific support mechanisms are implemented to complement power markets because the long-term price signal emanating from power markets is not sufficient enough to trigger the development of these capital-intensive technologies. Concerning capacity adequacy, several market failures explain why the reference energy-only market design fails to guarantee a socially acceptable security of supply. Thus, different capacity markets are suggested to improve this long-term coordination function.

In order to analyse the two key research topics, namely market-based investments in LCT and capacity adequacy issues in mature markets, the **second chapter** focuses on modelling investment decisions in electricity markets and long-term dynamics of power systems. In liberalised electricity systems, investment decisions are made by

private agents in a risky environment. In practice, investment decisions are mainly based on economic criteria including the Net Present Value (NPV) or the Internal Rate of Return (IRR). These decisions can also be influenced by investors' risk aversion through risk management tools, including the use of a risk-adjusted discount factor or utility functions.

Concerning long-term modelling of power systems, there are three major modelling families: (i) optimisation models which focus on long-term equilibriums resulting from cost minimisation or profit maximisation, (ii) microeconomic equilibrium models which allows for the representation of different imperfect competitive environments and (iii) simulation models which focus on the temporal evolution of complex systems. From different perspectives, these three modelling families allow for the study of liberalised power systems under various assumptions on investment process, competition or risk aversion. Belonging to simulation models, System Dynamics (SD) modelling constitutes an original approach by representing an investment process based on economic criteria of private investors with bounded rationality while considering long-term uncertainties and construction lead-times of power plants. Thus, this explains our methodological choice based on SD modelling which is suitable for representing the temporal evolution of the electricity generation mix resulting from private investment decisions which are represented as close as possible to realistic investment decisions in power systems.

Developed for this research project and belonging to SD modelling, the Simulator of Investment Decisions in the Electricity Sector (SIDES) model simulates the temporal evolution of a given power system over several decades. It represents a representative private investor with various risk aversion assumptions, evolving within different market architectures including the energy-only market but also the addition of a capacity mechanism. It takes into account both new investment and closure decisions for a set of conventional and renewable technologies. The detailed representation of hourly electricity markets under perfect competition combined with several weather scenarios enables the study of power systems with variable RES-E characterised by uncertain hourly production.

Focusing on the development of LCTs and in particular RES-E, the objective of the **third chapter** is to assess whether the implementation of a carbon price (which is translated into an increase of the variable cost of each generating technology according

to its emission factor) would trigger market-based investments in wind power. The conclusion is that the transition to a full market integration of on-shore wind power and more generally of variable RES-E should be gradual and supported by strong political commitments reflected by a high and stable carbon price. Without political actions to guarantee this high and stable carbon price, the sole market revenues are unlikely to trigger investments in RES-E and thus out-of-market mechanisms would be necessary, particularly within a system with an important existing nuclear capacity.

More specifically, the chapter questions the market-based development of on-shore wind power, taken as a representative mature RES-E. Simulations with the the SIDES model performed for different carbon prices make it possible to estimate what carbon price is required to trigger market-based investments in wind power. The case study is carried out under the assumption of a known and fixed carbon price over the twenty-year period, and for a risk-neutral representative private investor. The results highlight a very significant gap between the carbon price which makes wind power competitive in Levelised Cost Of Electricity (LCOE) analysis and the carbon price which triggers market-driven investments in wind power in the simulations of investments in electricity generation. This suggests that market-driven development of variable RES-E needs a strong political commitments to implement a high and stable carbon price, or if this is not the case, out-of-market support mechanisms should be added. Besides, simulations conducted in a system with a remaining open nuclear option show that nuclear plants further impedes the development of wind power. This is explained by at least two elements which gives an even greater economic value to nuclear assets in the context of hourly power markets: similarly to wind power, the variable generation cost of nuclear power is insensitive to the carbon price but contrary to wind power, nuclear power benefits from a dispatchable generation.

Focusing on security of supply, the objective of the **fourth chapter** is to quantify how different market designs, including the implementation of a capacity-wide capacity mechanism, can enhance the capacity adequacy and the resulting social welfare of power systems. This issue is addressed in the context of mature power markets with conventional thermal power plants under transition paths characterised by a stable electricity load as a result of energy efficiency efforts and facing exogenous entries of variable RES-E. Conclusions are of two types. Firstly, the results show that the energy-only market with price cap is ineffective to ensure capacity adequacy in this context.

Secondly, a well-designed capacity mechanism is an efficient solution to enhance capacity adequacy expressed in terms of socially acceptable level of Loss Of Load Expectation (LOLE). More specifically, the capacity market is identified as the best option for regulators when compared to an energy-only market with or without a price cap. The analysis of these market architectures is carried out for different assumptions about the risk aversion of private investors under two energy transition paths: (i) one characterised by exogenous entries of wind power and (ii) another characterised by exogenous closures of some coal and nuclear plants combined with the same exogenous entries of wind power as in the first case. Considering these two transition scenarios, characterised by a need of closures in the first case and a need of new investments in the second one, the results allow for the same conclusions: adding a capacity market or removing the price cap both prove beneficial to LOLE and social welfare. Depending on the scenario considered and on the assumption on risk aversion of private investors, these identified benefits represent an annual increase of the social welfare in the range of [M€ 100 ; M€ 500] compared to the benchmark energy-only market with price cap, corresponding to [0.3% ; 2.2%] of annual energy revenues in the considered system. Besides, when risk aversion is taken into account in the modelling of investment decisions, the capacity mechanism market design is significantly more efficient in terms of social welfare than the energy-only market with scarcity pricing.

At last but not least, this chapter also brings specific methodological insights by carrying out an analysis with and without considering risk aversion of private investors. This highlights that taking into account investors' risk aversion is crucial in comparing market architectures which can involve very different levels of uncertainties for generators.

Avenues for future researches

To broaden our research activities, further work could bring additional insights on the long-term coordination of investments by power markets.

The existing diversity of approaches to analysing power systems allows for different and complementary insights on the understanding of these complex systems. Among these approaches, system dynamics modelling appears as a relevant methodology along with optimisation models and microeconomic equilibrium models to simulate power markets and their investment incentives for private investors and to effectively focus on temporal

evolution of power systems. First, depending on objectives of further researches, the SIDES model could be further developed to integrate various elements as, for example, simulating different market areas or considering additional constraints from power plants or transport networks. Moreover, analysing the effects of increasing the number of uncertain variables and in particular considering the uncertainty on fuel prices (and eventually on the carbon price) could provide additional insights on power systems. It could also be relevant to analyse the sensitivity of the results to the correlation between the hourly electricity demand and the production profiles of various RES-E. Another relevant sensitivity analysis could lies in estimating how the effectiveness of various market designs (in particular those considered in chapter IV) is affected by the quality of their calibration.

Second, further analysis could estimate how the addition of a capacity mechanism affects the market-based development of variable RES-E and the resulting capacity adequacy, in effect linking the two research axes. By supposing that a political commitment allows for a high and fixed carbon price, investments in RES-E could be simulated based on revenues from power markets without any out-of-market support scheme using the SIDES model with a capacity mechanism which covers conventional capacities as well as RES-E ones (with adjusted capacity credits).

Third, a relevant further work could analyse how enhancing intraday and real-time markets could change the investment process and the resulting evolution of the electricity generation mix. Indeed, the role of short-term balancing and ancillary services markets become more and more important in a context of large variable and decentralised generation. Then, in this context, the revenues from these markets would be increasingly significant in the investment choices in conventional flexible plants. Thus, the improvement of these markets constitutes relevant issues for the design of future power markets' architecture.

Finally, the SIDES model provides a relevant methodological framework for future researches on long-term issues of power markets and constitutes a basis for further development of simulation models.

Appendix A

Glossary and nomenclature

This appendix is a support for the thesis reader. The first section provides the definition of the main terms used in the dissertation. The second section details the nomenclature used in the description of the Simulator of Investment Decisions in the Electricity Sector (SIDES) in section II.3.

A.1 Glossary

Costs of generating units

Investment cost refers to the cost needed to build a power plant, including pre-operating cost. It is generally expressed in € per MW of installed capacity. Once the decision to build the power has been undertaken, the investment cost should be considered as sunk cost. Some would prefer using overnight cost instead of investment cost. The overnight cost is defined as the sum of the investment cost and the financial interests of the construction period.

Annual operation and maintenance (O&M) cost refers to the cost of scheduled services and replacement of components needed to guarantee that the power plant is available to generating electricity. This cost is to be paid even if power plant do not generate electricity within the whole year. The distinction can be made between:

- fixed O&M cost that is not related to the volume of electricity generated within the year, expressed in € per installed MW and per year;

- variable O&M cost that depends on the volume of electricity generated within the year, expressed in € per generated MWh.

Variable cost of generating electricity is defined as in microeconomics textbooks. It corresponds to the cost proportional to the volume generated. It mainly refers to the cost of the fuel, the variable O&M cost and eventually the cost associated to carbon emissions. It is expressed in € per generated MWh.

Annualised fixed cost refers to the sum of annual O&M cost and the investment cost expressed in equivalent value per year.

A.2 Nomenclature

The annualised fixed cost corresponds to the sum of the annualised investment cost and the annual operation and maintenance cost as detailed in equation A.2.

$$AIC_{\chi} = \frac{IC_{\chi}.r}{1-(1+r)^{-T_{\chi}^{L}}} \tag{A.1}$$

$$FC_{\chi} = OC_{\chi} + AIC_{\chi} \tag{A.2}$$

$$EP_{\chi}(y) = \sum_{h=1}^{8760} EP_{\chi}(h,y) \tag{A.3}$$

χ	Index of the generating technology. $(1 \leq \chi \leq N)$
y	Index of the year.
h	Index of the hour. $(1 \leq h \leq 8760)$
$L(h, y)$	Electricity demand for the hour h of the year y.
κ_χ	Nominal power capacity of the technology χ.
$K_\chi(y)$	Installed capacity of the technology χ in the year y.
$y(F, \chi)$	First commission year of the power plant.
IC_χ	Investment cost in €/MW.
AIC_χ	Annualised investment cost in €/MW.year.
FC_χ	Annualised fixed cost in €/MW.year.
OC_χ	Annual operation and maintenance (O&M) in €/MW.year.
VC_χ	Fuel and carbon variable cost of a power plant of the technology χ.
$p(h, y)$	Market price for the hour h of the year χ.
$EP_\chi(y)$	Total electricity production of a power plant of the technology χ in the year y.
$EP_\chi(h, y)$	Electricity production of a power plant of the technology χ for the hour h of the year y.
$ENP_\chi(y)$	Estimated net profit of a power plant of the technology χ for the year y.
$MT.ENP_\chi$	Estimated net profit of a power plant of the technology χ on the mid run.
T_χ^C	Construction time of a power plant of the technology χ.
T_χ^L	Lifetime of a power plant of the technology χ.
Lf_χ	Load factor of the technology χ.
CAP	Price cap of the energy-only market.
r	Annual discounted rate.
F_χ	Normative capacity factor of a power plant of the technology χ.
$CC_\chi(y)$	Capacity certification of a power plant of the technology χ in year y.
$CB_\chi(y)$	Capacity bid offered by the technology χ in year y on the capacity market.
$CP(y)$	Capacity price in year y on the capacity market.
$CR(y)$	Capacity remuneration of a power plant of the technology χ in year y.

Table A.1: Nomenclature

Appendix B

Utility and mean-variance objective functions

B.1 Common utility functions

Classically, the different utility functions (noted $U(x)$ with x the agent's wealth) can be characterised by two classical measures of the degree of risk aversion introduced by Pratt (1964), Arrow (1971):

- the absolute risk aversion coefficient defined by $R_A(x) = -\frac{U''(x)}{U'(x)}$;
- the relative risk aversion coefficient defined by $R_R(x) = -x\frac{U''(x)}{U'(x)}$.

The classical utility functions are presented in below with a the level of risk aversion. Historically, the CARA and CRRA functions were proposed by Arrow (1965, 1970) and Pratt (1964). The function HARA introduced by Merton (1971) is a general expression which depends on the choice of three parameters (a, b, c).

The choice of a utility function is particularly prone to criticisms. It can strongly depends on the considered sector or context. Based on an experimental study, Levy (1994) concludes that the absolute risk aversion coefficient R_A decreases in wealth while the relative risk aversion coefficient R_R is constant or decreases in wealth.

Constant Absolute Risk Aversion (CARA)

$$U(x) = -\frac{1}{a}e^{-ax} \text{ with } a \geq 0 \tag{B.1}$$

The CARA function is characterised by an absolute risk aversion coefficient $R_A(x) = a$ which is constant with the agent's wealth.

Constant Relative Risk Aversion (CRRA)

$$U(x) = \begin{cases} \frac{x^{1-a}}{1-a} & \text{with } a > 0 \text{ and } a \neq 1 \\ ln(x) & \text{if } a = 1 \end{cases} \tag{B.2}$$

The CRRA function is characterised by an absolute risk aversion coefficient $R_A = a/x$ which decreases with the agent's wealth while its relative risk aversion coefficient $R_R = a$ is constant.

Increasing Absolute Risk Aversion (IARA)

$$U(x) = ax - \frac{1}{2}x^2 \text{ with } x \leq a \tag{B.3}$$

The IARA function is characterised by an absolute risk aversion coefficient $R_A(x) = \frac{1}{a-x}$ which increases with the agent's wealth.

Hyperbolic Absolute Risk Aversion (HARA)

$$U(x) = a(b + \frac{x}{c})^{1-c} \text{ with } \frac{a(1-c)}{c} > 0 \text{ and } b + \frac{x}{c} > 0 \tag{B.4}$$

Depending on the choice of the parameters (a, b, c), the HARA function allows for the representation of all the aforementioned utility functions.

B.2 Equivalence between the exponential utility function and the mean-variance objective function

This section details the equivalence between maximising the expected value of a Constant Absolute Risk Aversion (CARA) utility function (P.1) and maximising the mean-variance

objective function (P.2) which depends on the mean value μ and the standard deviation σ.

$$(P.1) : \max EU(x) \qquad\qquad (P.2) : \max(\mu - \frac{\alpha}{2}\sigma^2)$$

The utility function is supposed to be a CARA utility function as defined in equation B.5 with α the level of risk aversion ($\alpha > 0$) and x the level of consumption or the wealth of the considered agent. The function accordingly defined is concave in order to represent risk aversion rather than risk-seeking. CARA utility function are characterised by a constant absolute risk aversion R_A as expressed in equation B.6.

$$U(x) = -e^{-\alpha.x} \tag{B.5}$$

$$R_A(x) = -\frac{u''(x)}{u'(x)} = \alpha \tag{B.6}$$

The wealth x is supposed to follow a normal distribution $N(\mu; \sigma^2)$ for which μ is the mean value and σ is the standard deviation. A normal distribution is characterised by its density function given in equation B.7 which follows the relation B.8.

$$F(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(x-\mu)^2}{2\sigma^2}} \tag{B.7}$$

$$\int_{-\infty}^{\infty} \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(x-\mu)^2}{2\sigma^2}} dx = 1 \tag{B.8}$$

Thus, under these assumptions, the expected utility is given by equation B.9

$$EU(x) = \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{\infty} U(x)\ e^{-\frac{(x-\mu)^2}{2\sigma^2}} dx = \frac{1}{\sigma\sqrt{2\pi}} \int_{-\infty}^{\infty} -e^{-\alpha.x}\ e^{-\frac{(x-\mu)^2}{2\sigma^2}} dx \tag{B.9}$$

Then, the expression can be simplified by separating the terms depending on x from the ones not depending on x. In particular, the following relation is valid:

$$\begin{aligned}\alpha x + \frac{(x-\mu)^2}{2\sigma^2} &= \frac{1}{2\sigma^2}\left((x-\mu+\alpha\sigma^2)^2 + 2\alpha\mu\sigma^2 - (\alpha\sigma^2)^2\right) \\ &= \frac{(x-\mu+\alpha\sigma^2)^2}{2\sigma^2} + \alpha(\mu - \frac{\alpha\sigma^2}{2})\end{aligned}$$

Given this relation, equation B.9 becomes:

$$EU(x) = -\frac{1}{\sigma\sqrt{2\pi}} e^{-\alpha(\mu-\frac{\alpha\sigma^2}{2})} \int_{-\infty}^{\infty} e^{-\frac{(x-\mu+\alpha\sigma^2)^2}{2\sigma^2}} dx \tag{B.10}$$

Finally, given that the integral in equation B.10 equals to $\sigma\sqrt{2\pi}$ by using relation B.8, we get:

$$EU(x) = -e^{-\alpha(\mu-\frac{\alpha\sigma^2}{2})} \tag{B.11}$$

Then, the conclusion arises immediately:

$$\max EU(x) \Leftrightarrow \max(\mu - \frac{\alpha}{2}\sigma^2) \tag{B.12}$$

Appendix C

Understanding the basics of the SIDES model

The SIDES model is a tool to simulate investment decisions in power systems (see section II.3). Its functioning is based on the modelling of investment process rather than on the optimisation of the generation mix to serve the electricity demand at least cost as would do a benevolent planner. This appendix proposes a case study carried out to help the understanding of the functioning of the SIDES model compared to the *screening curves* approach.

C.1 Presentation of the case study

Three different cases are tested with the SIDES model in order to enlighten its functioning. The simulations are carried out with an energy-only market with a price cap set at € 20,000 /MWh and for risk-neutral investors. The three cases only differ on the choice of the investment criterion and on the cost structure of power plants. Table C.1 details these two parameters for each case. In particular, note that for these assumptions, coal power plants start before CCGT because the variable generation cost of coal plants is supposed to be lower than the one of CCGT.

- **Case A** is defined in order to be very close to the *screening curves* approach. The investment criterion corresponds to the NPV expressed in €/MW of installed

	Case A	**Case B**	**Case C**
Investment criterion	NPV per MW	NPV per MW	PI
Cost structure	Equivalent annual cost	Investment cost + Annual O&M cost	Investment cost + Annual O&M cost

Table C.1: Definition of the different cases

capacity. The cost structure is largely simplified: there is no distinction between upfront investment cost and annual O&M cost. Instead, only an annual investment cost is defined and equals to the annualised fixed cost which is the sum of value of the investment cost and the annual O&M cost. Thus, decommissioning decision are based on the comparison of annual revenues and annualised fixed cost.

- **Case B** is an intermediate between the two other cases. The investment criterion is the NPV per installed MW as case A while the cost structure is the same as in case C.
- **Case C** corresponds to the general use case of the SIDES model. The investment criterion is the profitability index (PI) which is the ratio between the NPV and the initial upfront investment cost. The cost structure imitates the real one: an upfront investment cost and an annual O&M cost. In this case, investment cost are considered as sunk cost at the stage of retirement decision which is based on the comparison of annual revenue to annual O&M cost.

The simulation setting remains very simple in order to facilitate the understanding. The electricity demand is supposed to be constant on the whole period and there is only one weather scenario. Thus, for an investor with perfect anticipation of the future at it is the case here, there is absolutely no uncertainty on the electricity demand.

Four technologies are considered in the simulations: nuclear power plants (Nuclear), coal-fired power plants (Coal), combined cycle gas turbines (CCGT) and oil-fired combustion turbines (CT). Table C.2 provides the cost and technical assumptions. In order to fasten the simulations, an initial mix is defined. This initial mix is set so that the total generation capacities are clearly not sufficient with respect to the electricity demand and therefore, endogenous investment are needed in the simulations. The initial mix is composed of 43.8 GW of nuclear, 5.4 GW of Coal, 17.3 GW of CCGT and 6.6 GW of CT.

	Nuclear	Coal	CCGT	CT
Investment cost (k€/MW)	2,900	1,400	800	590
Annual O&M cost (k€/MW/year)	100	50	18	5
Equivalent annualised fixed cost* (k€/MW/year)	334	167	89	60
Variable cost (€/MWh)	10	42.3	66.1	161.8
Discrete power capacity (MW)	50	50	50	50
Construction time (years)	6	4	2	2
Life time (years)	60	40	30	25

* The annualised fixed cost is computed with annual discount rate of 8%.

TABLE C.2: Plant parameters used in simulations

The simulations are carried out for a period of 80 years for a representative technology-neutral investor with no risk aversion and with perfect anticipations of the future.

C.2 Results

C.2.1 Optimal generation mix by the screening curves approach

The *screening curves* approach is a commonly used optimisation method to define the optimal generation mix given assumptions on the load duration curve and generating technologies (see section II.2.2, figure I.1). The optimal generation mix obtained by the *screening curves* approach is considered as the reference mix (noted "RefMix") and is presented in figure C.1. It is composed of 52.4 GW of nuclear, 5.8 GW of coal, 18.2 GW of CCGT and 8.6 GW of CT, therefore a total installed capacity of 85.1 GW and a LOLE of 3 hours per year.

The reference mix, thus defined, is compared to the results obtained with the SIDES simulation in order to enlighten its functioning. Indeed, the three different cases tested with the SIDES model take us gradually further away from the *screening curves* approach. More specifically, the *screening curves* approach consists is finding at each step the less expensive installed MW to serve the remaining electricity demand. Thus, it fits with an investment criterion expressed as the NPV per installed MW. At the same time, the *screening curves* approach provides a static generation mix for a given load duration curve and therefore, there is no distinction between the cost structure to be considered for the investment or retirement process. At the end, the corresponding cost structure

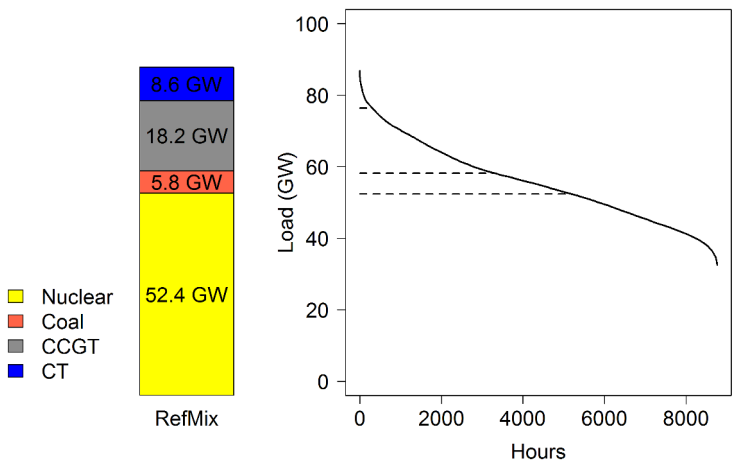


FIGURE C.1: Definition of the reference mix (RefMix)

is an annual equivalent fixed cost which embeds both the initial upfront investment cost and the annual O&M cost. This lead us to consider that case A as defined in table C.1 is very similar to the *screening curves* approach.

C.2.2 Simulations with the SIDES model

Simulations are conducted with the SIDES model for the three different cases defined above. Figure C.2 presents the evolution of the generation mix obtained in each case. At first sight, the results are quite similar: investments are needed at the beginning of the simulation and then, the generation mix slightly evolves in particular when some power plants reach the end of their lifetime.

Investment and decommissioning decisions detailed in figure C.3 give a better understanding of the differences between the three cases. First, significantly more decommissioning decisions occur in case A compared to cases B and C. This is explained by the cost structure defined in case A: early-retirement decisions are taken based on the comparison of revenues against the equivalent annual fixed cost which is largely higher than the sole annual O&M cost used in cases B and C. Secondly, there is a notable difference in the choice of invested technologies between cases A and B on the one hand, and case C on the other hand. Indeed, the investment criterion is different between cases A and B versus case C. Table C.3 details the estimation of the two considered investment criteria for the first economic test of the first simulated year (the existing generation mix is the same for the three cases at this stage of the simulations). It shows that the two criteria,

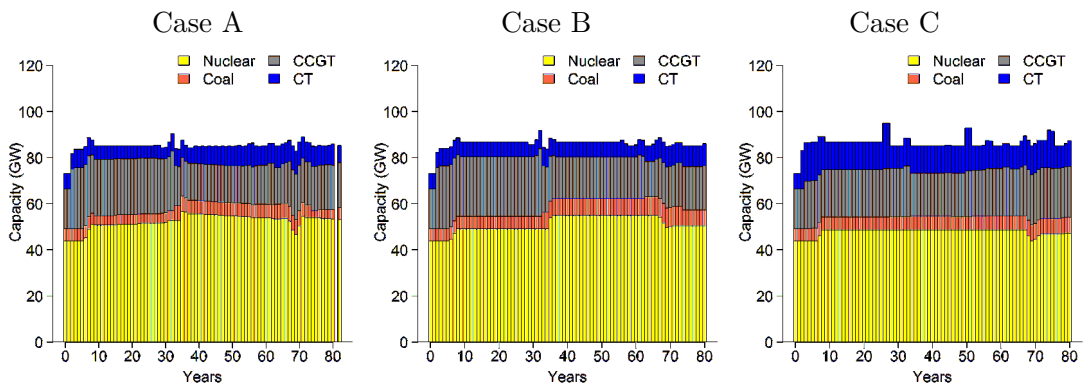


FIGURE C.2: Evolution of the generation mix over the 80-year period for the three cases

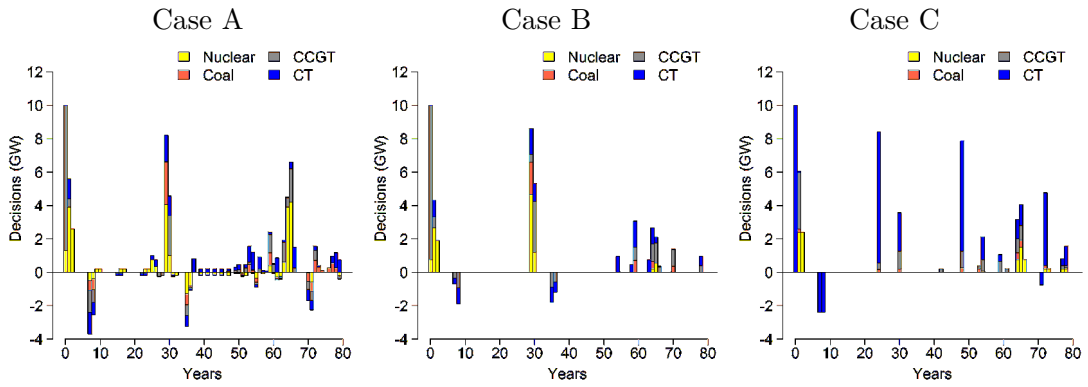


FIGURE C.3: Details on the decisions of new investments or early-retirements for the three cases

	Nuclear	Coal	CCGT	CT
NPV per MW (M€/MW)	118	113	**124**	116
PI (dimensionless)	41	81	155	**197**

TABLE C.3: Investment criteria estimated in the first year of the simulation

namely the NPV per MW and the PI, do not lead to the same choice: the NPV per MW leads to choose CCGT whereas the PI indicates to invest in CT because of its lower investment cost.

In order to compare the mix obtained in each case, figure C.4 and table C.4 detail the average mix resulting from each case which is defined as the mean capacity computed on the last 70 years of the simulation for each of the four technologies. This confirms that cases A and B provide a generation mix very close to the reference mix obtained by the *screening curves* approach (RefMix) whereas the generation mix obtained in case C

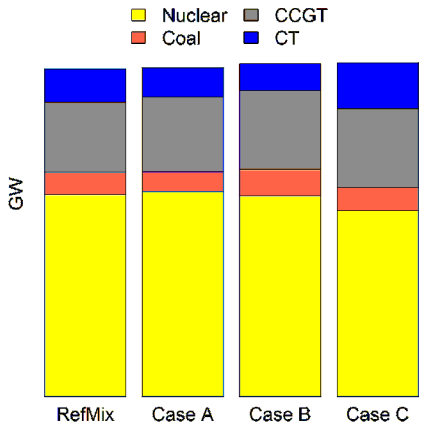


FIGURE C.4: Average mix (in GW) obtained in each case

	RefMix	**Case A**	**Case B**	**Case C**
Nuclear (GW)	52,4	53,2	52,1	48,2
Coal (GW)	5,8	5,2	6,8	6,1
CCGT (GW)	18,2	19,5	20,6	20,5
CT (GW)	8,6	7,6	6,9	11,9
Total (GW)	85,1	85,4	86,5	86,7

TABLE C.4: Comparison of the generation mix (in GW) on average over the last 70 simulated years for the three different cases, and the optimal generation mix (RefMix).

is slightly different with relatively more peakload plants and less baseload plants.

C.3 Insights on the functioning of the SIDES model

The case study presented in this appendix highlights the difference between the SIDES model and optimisation approaches as the *screening curves* method. By comparing the three different cases of simulation carried out, some insights can be drawn:

- The investment criterion can influence the dynamics of the generation mix. The criterion PI tends to foster peakload plants due to their relatively low upfront investment costs. The criterion NPV per MW tends to foster baseload or midload plants and follows a reasoning similar to the one of central planner rather than private investor.

- The cost structure of power plants influences the balance between new investments and early-retirements. Imposing a realistic cost structure with differentiation between investment cost and annual O&M cost – as it is the case in the original use of the SIDES model – can result in existing plants remaining in operation while facing losses with respect to their equivalent annual fixed costs, therefore leading to an eventual tendency to over-capacity.

Appendix D

Price formation on a capacity market

As exposed in the economic theory, market price corresponds to the marginal cost of the product under the assumption of pure and perfect competition. On the energy market, the hourly market price reflects the marginal short-run cost of producing an additional MWh of electricity above the corresponding hourly electricity demand. Similarly, the annual capacity price should reflect the cost of making available an additional certified MW above the corresponding annual capacity obligation. Depending on the situation, this additional certified MW comes either from not closing an existing power plant or building a new power plant.

This appendix proposes a method to define the marginal capacity cost by analysing how producers determine the capacity price offered on the capacity market.

D.1 Preliminary precisions

D.1.1 Which costs should be considered?

It's important to distinguish among stranded costs (or sunk costs) and avoidable costs. Indeed, capacity bids depends only on avoidable costs.

Before taking the decision of building a power plant, all costs should be considered as avoidable. As a consequence, at least for the first commissioning year of the power

Situations	**Costs to be considered to define capacity offer**
Existing capacity	Only variable generation cost and operation and maintenance cost.
New capacity (under project)	All costs: variable generation cost, operation and maintenance cost and investment cost.

Table D.1: Distinction between existing and new capacities concerning costs to be considered to define capacity offer.

plant, the price offered on the capacity market will take into account all costs. Indeed, as the capacity market is proposed four years ahead the delivering year, it is possible to get a capacity certificate and to sell if before the power plants is built. Even if the construction time of the power plant is more than four years, we suppose that capacity certificates can be sold as forward capacity products.

Once a power plant is build, its investment cost becomes stranded as there is no choice but to repay the loan. However, the annual operation and maintenance cost can still be avoided (at least partly) by closing or mothballing the power plant. Consequently, for an existing power plant, the price offered on the capacity market depends only on the annual operation and maintenance cost but not on the investment cost.

In the following discussion, one should keep in mind that costs to be considered are different for existing or new capacities as outlined in table D.1.

D.1.2 Missing money: a useful distinction

This distinction between existing and new power plants highlights the need to define the well-known "missing money" that is widely employed in the literature. Indeed, it must be precise to which cost refers the missing value. A distinction must be made between:

- The missing money referring to the lack of revenue to cover annual fixed cost. In this case, both annual operation and maintenance cost and investment cost (through an annualised value) are taken into account. This could be referred to as "long-term missing money".
- The missing money referring to the lack of revenue to cover annual operation and maintenance cost only. This definition should be used when talking about existing power plants. This could be referred to as "short-term missing money".

While this distinction could seem trivial, the precision is rarely made in the literature. Nevertheless, the value obtained for the missing money is very different according to the definition employed simply because annual O&M costs on one part and annual fixed costs on the other part are of different magnitudes.

D.2 Formation of the capacity price offered by producers

Theoretically, the price offered by a producer for the delivery year y corresponds to his additional cost to guarantee the availability of the power plant in year y. This depends on the management strategy defined by the producer. If the power plant was already planned to be available, there is no additional cost for availability. But if the power plant was to be shut down, there is an additional cost to keep the power plant available.

This section reviews how the price offered is theoretically defined in different cases. The distinction is made between existing power plants and new investments. The objective is to propose a way to compute the capacity bid (noted $CB_\chi(y)$) offered by a technology χ for the delivery year y based on economic considerations. The discount rate used by the considered private investor is noted r. The capacity certification of the power plant is noted $CC_\chi(y)$. The complete nomenclature is precised in appendix A.

D.2.1 Existing power plants

In this section, we consider a producer that owns a power plant which is already in operation and has to decide the price offered on the capacity market. At this stage, investment cost is considered as a sunk cost and does not influence the price offered on the capacity market.

Simple case without mothballing option

In this section, an existing power plant is considered. This power plant is supposed to still have several years to operate before reaching the end of its lifetime. The last year of its lifetime is noted y_{end} as illustrated in figure D.1. For sake of simplicity, mothballing option is not considered in this section.

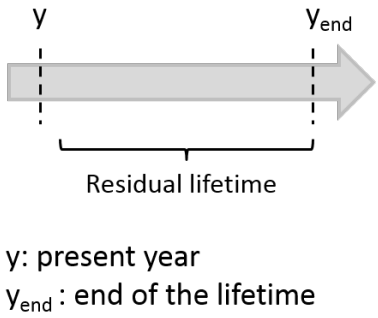


FIGURE D.1: Illustrative time-line for an existing capacity.

- Estimate the discounted net profit from the energy market (noted $ENP_\chi(y+1; y_{end})$) and the discounted capacity remuneration (noted $CR_\chi(y+1; y_{end})$) for the whole residual period from year $y+1$ to year y_{end}. The net profit from the energy market corresponds to the difference between energy revenues and variable generation costs.

$$ENP_\chi(y+1; y_{end}) = \sum_{i=y+1}^{y_{end}} \frac{ENP_\chi(i)}{(1+r)^i} \tag{D.1}$$

$$CR_\chi(y+1; y_{end}) = \sum_{i=y+1}^{y_{end}} \frac{CR_\chi(i)}{(1+r)^i} \tag{D.2}$$

- Estimate the energy revenue for year y: $ENP_\chi(y)$

- Compute the financial balance over the period RL (thus, without any capacity revenue in year Y) and decides if the power plant should be decommissioned or not. The financial balance corresponds to the difference between revenues and variable production cost plus annual O&M cost. Investment cost of the power plant is not considered at this stage (sunk cost).

$$Balance = ENP_\chi(y) + ENP_\chi(y+1; y_{end}) + CR_\chi(y+1; y_{end}) - \sum_{i=y+1}^{y_{end}} \frac{K_\chi.OC_\chi}{(1+r)^i} \tag{D.3}$$

- **CASE 1:** $Balance \leq 0$

  The capacity owner decides to continue to run the power plant no matter what the capacity price on year Y would be. Therefore, the capacity bid offered on the capacity market for year Y is theoretically zero.

$$CB_\chi(y) = 0 \tag{D.4}$$

- **CASE 2:** *Balance* < 0

  Without any capacity revenue on year Y, the capacity owner would decide to close the power plant. The price offered on the capacity market for year y corresponds to the amount needed to ensure financial equilibrium[1].

$$CC_\chi(y).CB_\chi(y) = \Big(\sum_{i=y+1}^{y_{end}} \frac{K_\chi.OC_\chi}{(1+r)^i}\Big) - ENP_\chi(y) - ENP_\chi(y+1; y_{end}) - CR_\chi(y+1; y_{end}) \tag{D.5}$$

This basic case illustrates that the capacity price offered in year y depends on an estimation of the capacity revenues over the period RL excluding y. This difficulty is similar to storage management for hydro power for which the use value of water is determined through an estimation of energy prices on the spot market for the next hours or days. However, the level of uncertainty in the energy market over hours or days might not be comparable with the uncertainty in the capacity market over several years.

With mothballing option

A producer has the option to mothball a power plant for a few years[2]. Mothballing is likely to happen when the power plant is not profitable on the very short term but is estimated to return to profitability after this period of mothballing. The option of mothballing reduces losses during this period of non profitability. In practice, mothballing a power plant also requires specific costs (noted $MthC_\chi(y)$).

The illustrative case considered here supposed that the mothballing period would last from year y to $y+2$ included as illustrated in figure D.2.

- Estimate the discounted losses (noted $L1$) if the power plant is mothballed.

$$L1 = ENP_\chi(y+3; y_{end}) + CR_\chi(y+3; y_{end}) - MthC_\chi(y; y+2) - \sum_{i=y+3}^{y_{end}} \frac{K_\chi.OC_\chi}{(1+r)^i} \tag{D.6}$$

[1]The producer decides to offer the lack of money to ensure financial equilibrium on a certain number of years. Here, to keep it simple, we suppose that the whole amount is offered on the first year.

[2]Typically, the mothballing period can last from one to five years. Seasonal mothballing of few months within a year is not considered because it is out of the scope of a capacity market.

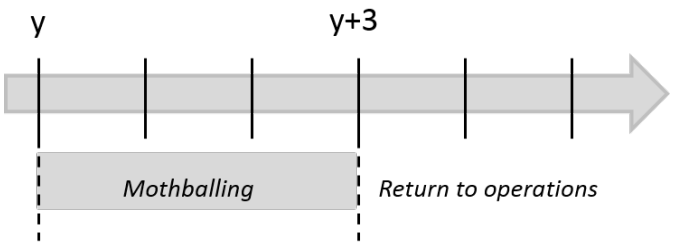


FIGURE D.2: Illustrative time line for mothballing situations.

where $MthC_\chi(y; y+2)$ is the discounted costs of mothballing the power plant from year y to year $y+2$.

$$MthC_\chi(y; y+2) = \sum_{i=y}^{y+2} \frac{MthC_\chi(i)}{(1+r)^i} \tag{D.7}$$

In this illustrative case, $L1$ is negative.

- Estimate the discounted losses (noted $L2$) if the power plant is still in operation but without capacity revenues during the mothballing period.

$$L2 = ENP_\chi(y; y_{end}) + CR_\chi(y+3; y_{end}) - \sum_{i=y}^{y_{end}} \frac{K_\chi.OC_\chi}{(1+r)^i} < 0 \tag{D.8}$$

In this illustrative case, $L2$ is also negative.

- Without capacity market, the power plant is mothballed if: $|L1| < |L2|$. We suppose that this relation is valid. In this case, the sum of the capacity bids for the delivering years corresponding to the mothballing period (from year y to year $y+2$) should theoretically be equal to $|L2| - |L1|$. The producer chooses which proportion is to be offered on the capacity market each year of the mothballing period.

$$\sum_{i=y}^{y+2} \frac{CC_\chi(i).CB_\chi(i)}{(1+r)^i} = |L2| - |L1| \tag{D.9}$$

If the mothballing can be decided year by year (if mothballing costs are linear with time), the approach proposed here becomes simpler: the mothballing period can be limited to one year and the analysis is made year after year.

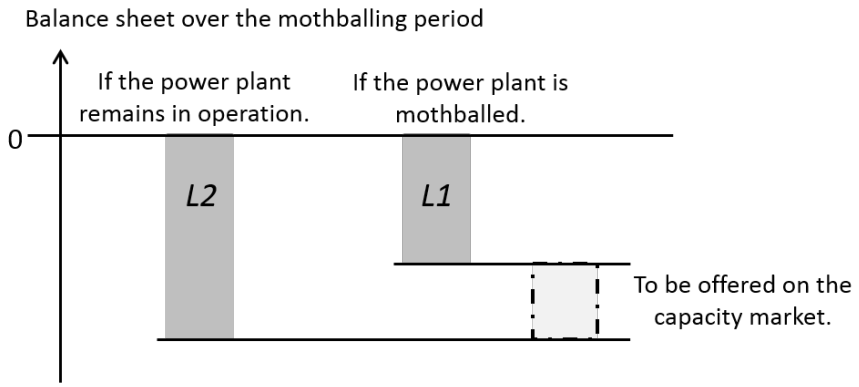


FIGURE D.3: Illustration of the value proposed on the capacity market in case of mothballing option.

For a power plant at the end of its lifetime

At the end of its lifetime, a power plant is generally shut down. Nevertheless, a producer can decide whether or not to undertake upgrade works in order to extend the lifetime of the power plant (refurbishment for technical reasons or to fulfil new standards). This case is very similar to the case of a new investment but with a different investment cost, except that generally the decision cannot be postponed.

D.2.2 New power plants

This section focuses on new investment. The objective is to define how an investor should theoretically decide the price offered on the capacity market for the first year of operation of the power plant.

To make it easier, we consider than an investor would invest if the Net Present Value (NPV) of the project is greater than or equal to zero. In reality, decision making is much more complex. However, the following discussion remains valid in the general case: the rule "$NVP \leq 0$" should be understood as "the investor decides to invest in the project" whatever his investment criteria are.

Time management is an important feature of investment decisions which is taken into account in the following discussion.

New investment already profitable without capacity revenue on the first commissioning year

If the value of a new power plant is greater than zero without capacity revenue on the first commissioning year, the capacity price offered by this power plant should theoretically be zero. The capacity revenue of this project is seen as an extra income that increases its profitability.

In this case, the capacity price offered on the capacity market should theoretically be zero for the first commissioning year of the project.

Here, saying that the investment is already profitable without capacity revenue on the first commissioning year doesn't mean that it doesn't plan to get a capacity remuneration during its whole life, neither that effects of the capacity market are not taken into account. Indeed, the capacity market probably influences the generation mix (total capacity and shares of the different technologies). Those effects on the generation mix should be taken into account to estimate accurately energy revenues and capacity revenues for the whole life time.

In practice, a power plant needs time to be built with a specific construction lead-time depending on the considered technology. Given that the project is undertaken in the present year y, the power plant will be under operation from year $y + T_{\chi}^{C}$ with T_{χ}^{C} the specific construction lead-time of technology χ. The last operating year of the power plant is noted y_{end}.

New investment unprofitable without capacity revenue on the first commissioning year

If an investment is not economically profitable without capacity revenue on the first commissioning year, it is necessary to estimate its capacity revenue on the first year. The investment is to be undertaken if the project becomes profitable when taking into account capacity revenue of the first year.

- Estimate the discounted net energy revenues of the project for the whole lifetime: $ENP_{\chi}(y + T_{\chi}^{C}; y_{end})$

- Estimate discounted capacity revenues that seem realisable on the long run (after the first operating year): $CR(y + T_\chi^C + 1; y_{end})$

- The capacity bid offered for the first commissioning year should theoretically be equal to the lack of money to ensure economic profitability of the project according to equation D.10.

$$\frac{CC_\chi(y + T_\chi^C).CB_\chi(y + T_\chi^C)}{(1+r)^{T_\chi^C}} = K_\chi.IC_\chi + \Big(\sum_{i=y+T_\chi^C}^{y_{end}} \frac{K_\chi.OC_\chi}{(1+r)^i}\Big) - ENP_\chi(y + T_\chi^C; y_{end}) - CR(y + T_\chi^C + 1; y_{end}) \tag{D.10}$$

Moving forward an investment

This section deals with the case of an investment that has already been undertaken and for which there is still a delay before building construction to take place. In that case, the capacity price offered to move forward the construction of the power plant is related to time management.

We consider the case of an investor that has already decided to start building a new capacity. Let us suppose that according to his estimation, the best date for this investment is to start building the power plant in year $y + 2$ in order to start operating this new power plant in year $y + 5$, given that the construction time is three years. The investor has also the opportunity to start construction works now[3] (year y) so that the new power plant will be in operation in year $y + 3$. The situation is illustrated in figure D.4.

In this case, the investor is likely to move forward its investment to guarantee the availability of the power plant in year $y + 3$ rather than in year $y + 5$ if the capacity remuneration allows to fill the gap between the values of the two investment options.

- Estimate the net present value (noted $V1$) of the investment option 1 corresponding to starting operations in year $y + 5$. This should include all estimated capacity revenues. This investment is profitable for the investor: $V1 > 0$

[3]Note that in reality, this case should also be compared to the possibility of investing in year $y + 1$ so that the power plant comes on line in year $y + 4$. Investors would choose the best option between all options available at the time. Here, for sake of simplicity, this option was not considered.

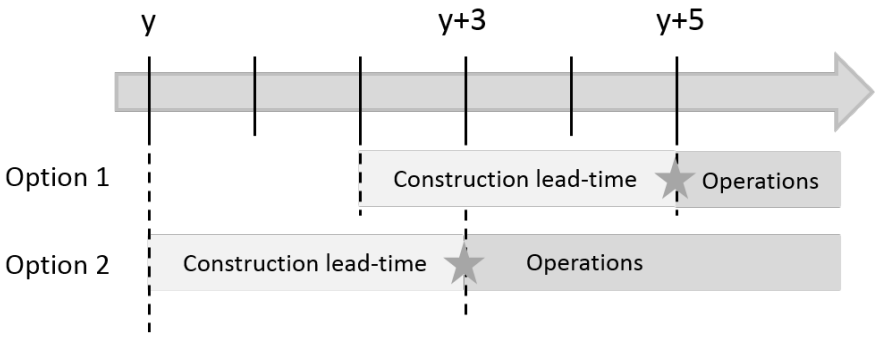


FIGURE D.4: Illustrative time-line of moving an investment forward.

- Estimate the net present value (noted $V2$) of the investment option 2 corresponding to starting operations in year $y+3$ (the investment is moved forward) without any capacity revenue for the first commissioning year. We supposed that $V2 < V1$, either a positive or a negative value

- Theoretically, the capacity on the capacity market for the year $y+3$ proposed by the investor which would move forward its investment project to guarantee the availability of the power plant in year $y+3$ follows equation D.11.

$$\frac{CC_{\chi}(y+3).CB_{\chi}(y+3)}{(1+r)^3} = V1 - V2 \tag{D.11}$$

D.2.3 Summary table

To make it simple, the different cases described above can be summarised by saying that the capacity price offered on the capacity market corresponds to the difference in value (if this value is positive) between unavailable capacity and keeping the capacity available for the delivering year. This estimation should incorporate only operation and maintenance cost for an existing capacity and also investment cost for a capacity under project. Finally, the analysis of the capacity bid of generators is summarised in table D.2.

	Situations	**Bid on the capacity market**
Existing capacity	Power plant which remains on operation for the following years without capacity revenue on the following year.	0
	Power plant unprofitable to be closed if doesn't get capacity revenue on the following year.	Lack of remuneration to keep the power plant in operation.
New capacity	$NPV \leq 0$ without capacity revenue on the first commissioning year	0
	$NPV < 0$ without capacity revenue on the first commissioning year	Remuneration needed to undertake the project. Need to define a bidding strategy on the capacity market.
	Moving forward an investment	Difference between the value of the project for the optimal date and the value to invest now.

Table D.2: Summary of capacity supply.

Appendix E

Electricity demand and wind data used in the simulations

This appendix provides details on the data (electricity demand and wind load factors) used in the simulations of chapters III and IV.

In all the simulations performed with the Simulator of Investment Decisions in the Electricity Sector (SIDES) model, historical scenarios are used for electricity consumption and load factors of wind power. This approach has the advantage of allowing historical relationship between electricity demand and electricity generation from wind power by using coherent historical scenarios for the two variables. Hence, the realised historical correlation between electricity demand and load factor of wind power is ensured without the need to define (or suppose) a correlation based on a probability distribution.

E.1 Data used in chapter III

The simulations presented in chapter III were carried out using 12 scenarios of electricity consumption and load factors of on-shore wind power which correspond to the French data for the period 2000-2011. Electricity consumption are from public data and load factors of on-shore wind turbines are RTE-internal data corresponding to the French area.

Minimum load (GW)	28.7 – 29.5 (29.0)
Maximum load (GW)	83.9 – 93.7 (88.6)
Average load (GW)	52.1 – 55.3 (53.5)

TABLE E.1: Descriptive statistics of electricity consumption scenarios used in chapter III.

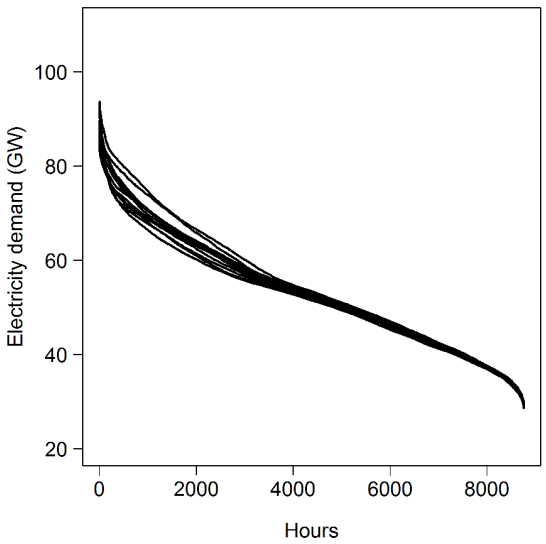


FIGURE E.1: Load duration curves of the 12 historical scenarios used in chapter III.

Table E.1 provides descriptive statistics of the 12 electricity consumption scenarios used in chapter III. The hourly electricity load varies between 28.7 GW and 93.7 GW. Figure E.3 shows the corresponding 12 load duration curves.

Concerning on-shore wind power, the average load factor is 21.6% for the considered data on the period 2000-2011.

Figure E.2 shows the scatter-plot of electricity consumption and load factor of wind power for each of the 12 historical scenarios. Estimated on the whole database of 12 scenarios, the Kendall rank correlation coefficient[1] between electricity consumption and wind load factor is 0.126, suggesting that there is no clear correlation between the two variables.

[1]The Kendall rank correlation coefficient (or Kendall's tau) is a statistical measure of the ordinal relation between two variables.

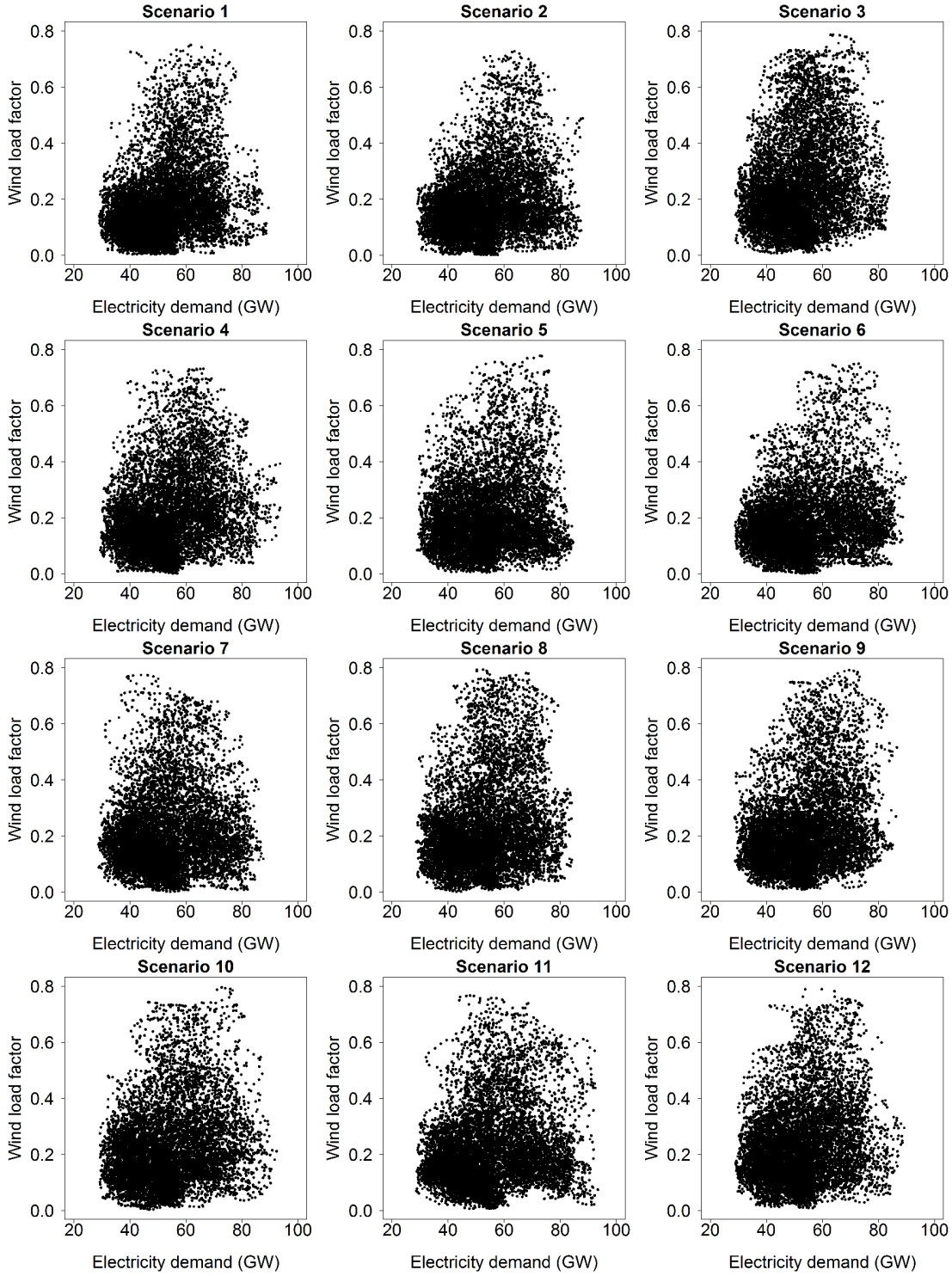


FIGURE E.2: Wind load factor versus electricity consumption, data used in chapter III.

E.2 Data used in chapter IV

The issue of capacity adequacy needs to represent in detail the large variations of the electricity consumption in order to take into account extreme peak events. To this end, the data based used in chapter IV should reflect events of high and low electricity demand. In France, the year 2012 is characterised by events of high electricity demand with the maximum historical peak load of 102.1 GW explained by extreme weather conditions. In order to best reflect the variation of the French electricity consumption, the historical scenarios used for the study on capacity adequacy presented in chapter IV was updated to include the year 2012.

The data used for the simulations of chapter IV corresponds to (i) historical public data of the French electricity consumption for the period 2003-2013 and (ii) load factors of on-shore wind turbines from RTE-internal data for the same period 2003-2013. The consumption data are adjusted for the consumption growth of the period by a multiplying factor[2].

Table E.2 provides descriptive statistics of the 11 electricity consumption scenarios used in the simulations of chapter IV. The hourly electricity load varies between 30.0 GW and 101.0 GW. Figure E.3 shows the corresponding 11 load duration curves.

Concerning on-shore wind power, the average load factor is 21.9% for the considered data on the period 2003-2013.

Figure E.4 shows The scatter-plot of electricity consumption and load factor of wind power for each of the 11 historical scenarios. Estimated on the whole database of 11 scenarios, the Kendall rank correlation coefficient between electricity consumption and

Minimum load (GW)	30.0 – 32.8 (31.9)
Maximum load (GW)	83.3 – 101.0 (90.7)
Average load (GW)	54.9 – 59.0 (56.4)

Table E.2: Descriptive statistics of electricity consumption scenarios used in chapter IV.

[2]The data adjustment is slightly different from the one realised for the data used in chapter III. This explains why the consumption scenarios are slightly different. However, this difference is not significant for the coherence of the two chapters.

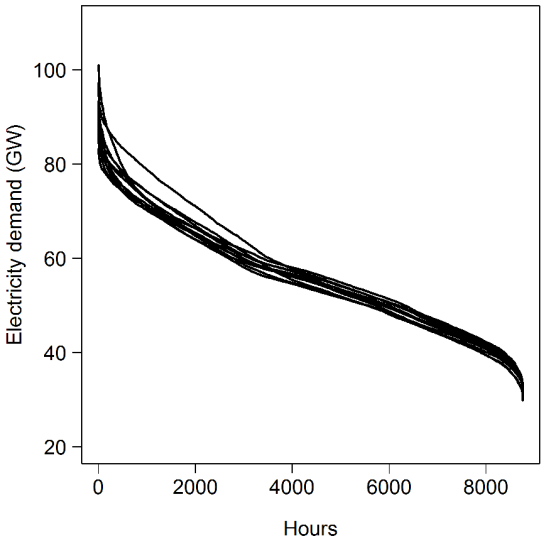


FIGURE E.3: Load duration curves of the 11 historical scenarios used in chapter IV.

wind load factor is 0.126, suggesting that there is no clear correlation between the two variables.

In the analysis of a capacity mechanism presented in chapter IV, the entry of wind power is set exogenously. At the end of the simulation period, there are 70 GW of wind power. The addition of 70 GW of wind power significantly influences the shape of the net[3] load duration curve as illustrated in figure E.5.

[3]The net load corresponds to the real electricity demand minus the electricity generated by wind power.

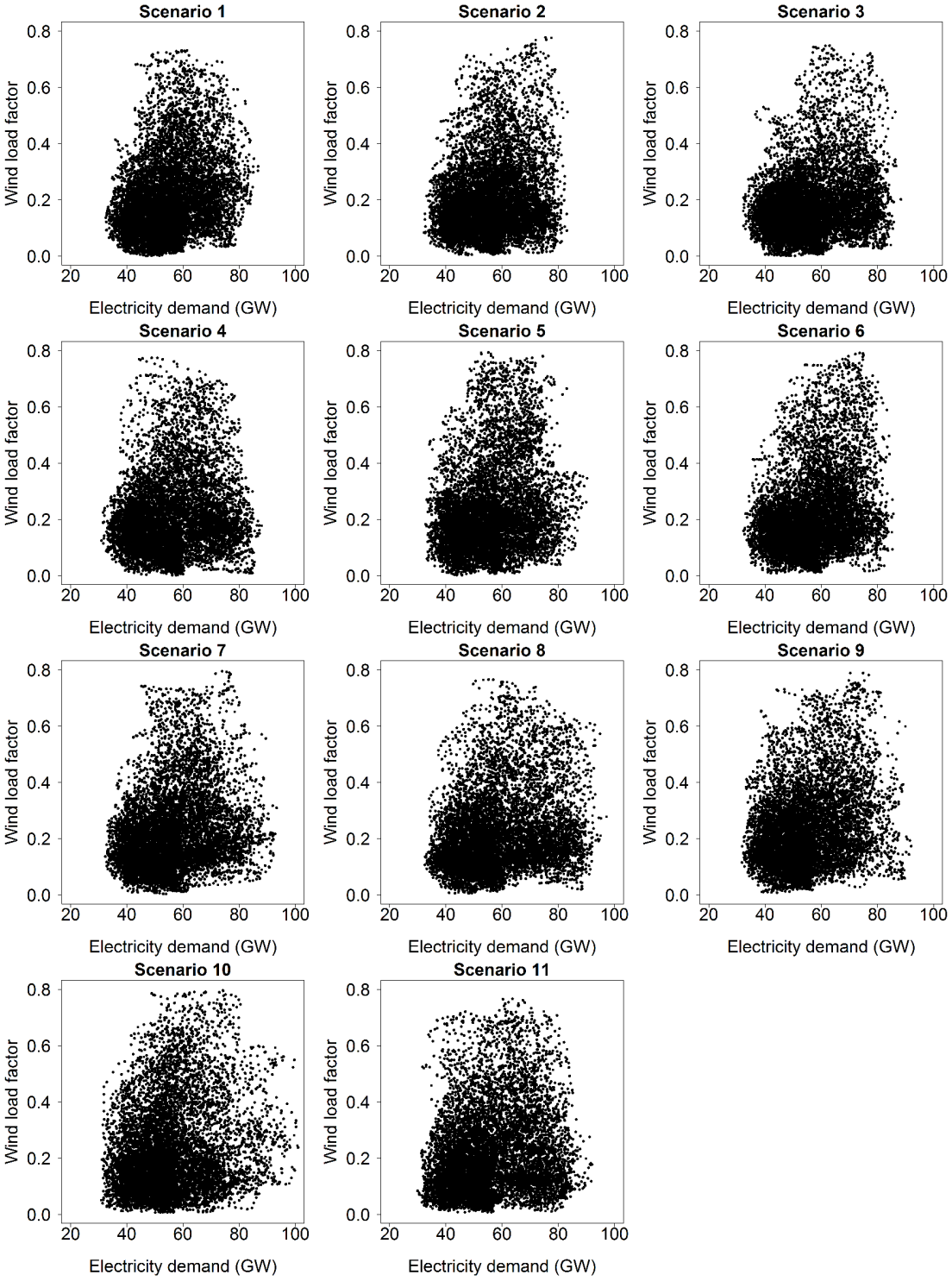


FIGURE E.4: Wind load factor versus electricity consumption, data used in chapter IV.

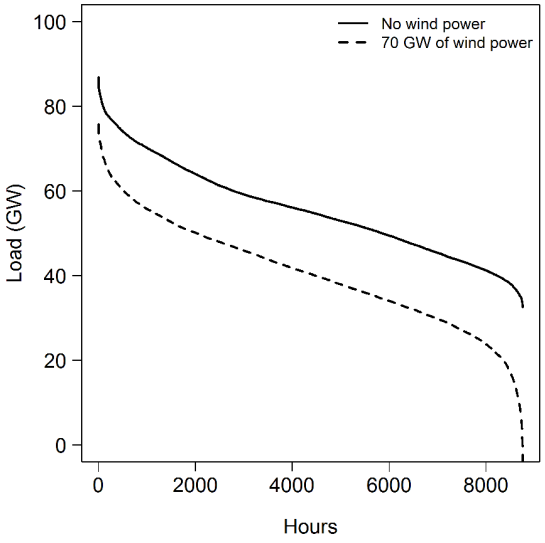


FIGURE E.5: Effect of the introduction of 70 GW of wind power on the load duration curve (scenario 1).

Appendix F

Résumé en français

Analyse des dynamiques d'investissement de long terme dans les marchés électriques sous contraites de développement des renouvelables intermittentes et d'adéquation de capacité

Introduction

Dans les systèmes électriques libéralisés, les marchés électriques sont supposés assurer la coordination de long-terme des investissements afin de garantir la sécurité d'approvisionnement, la viabilité et la compétitivité du secteur. Dans le modèle energy-only de référence, la coordination de long terme des investissements dans les différents équipements est réalisée par le signal provenant des marchés électriques caractérisés par un prix horaire s'alignant sur le coût marginal de production du dernier moyen appelé dans l'ordre de mérite. Cependant, en pratique, ce modèle est remis en question quant à sa capacité à déclencher des investissements dans les moyens de production intensifs en capital comme les technologies bas-carbone et en particulier les énergies renouvelables et quant à sa capacité à garantir la sécurité d'approvisionnement. Cette thèse cherche d'abord à caractériser ces défaillances de marché puis s'intérèsse à des solutions pour faire face à ces questions portant sur la fonction de coordination de long terme des marchés électriques.

- **Dans une architecture de marché sans aucun mécanisme de soutien spécifique à certaines technologies, quel prix du carbone pourrait permettre de décencher des investissements dans les technologies de production bas-carbone ?**

D'une part, le fonctionnement actuel des marchés électriques pose des questions sur leur capacité à déclencher des investissements dans les technologies bas carbones ou renouvelables, caractérisées par des investissements initaux élevés et par des coûts variables faibles voire nuls. Cependant, les enjeux liés au changement climatique et à la volonté des Etats d'être indépendants énergétiquement peuvent justifier la promotion de ces énergies d'un point de vue social. Dans ce contexte, les investissements dans certaines technologies bas carbone ou renouvelables sont actuellement encouragés dans beaucoup de pays par des mécanismes spécifiques hors-marché. En général, ces mécanismes de soutien se traduisent par une garantie de rémunération sur plusieurs années (typiquement au moins une dizaine d'années) associée à un niveau de risque faible.

D'autre part, ces mécanismes dédiés à accélérer le développement des énergies bas-carbone ou renouvelables sont à l'origine de la coexistence de deux régimes d'investissements différents : (i) un régime d'investissement basé sur une rémunération de l'énergie produite par les marchés électriques pour les technologies conventionnelles et (ii) un régime d'investissement hors-marché pour de nombreuses technologies faiblement émettrices de CO_2. De plus, alors même que le fonctionnement long terme des marchés électriques soulèvent encore des questions non résolues, l'arrivée massive et hors-marché des technologies bas carbone vient augmenter le risque-prix et le risque-volume pour les technologies conventionnelles compliquand encore davantage la coordination de long terme des investissements. Ainsi, ces défaillances constituent un paradoxe du point de vue de l'économie des marchés électriques (Finon, 2013) qui doit être étudié afin d'améliorer la securité d'approvisionnement des sytèmes électriques dans le future.

- **Dans quelle mesure un mécanisme de capacité peut-il améliorer la sécurité d'approvisionnement dans un système électrique faisant face à des politiques de transition énergétique ?**

Un autre point critique des marchés électriques libéralisés concerne leur aptitude à garantir un niveau de capacité installée suffisant du point de vue social. En effet, des doutes subsistent quant à la garantie de la sécurité d'approvisionnement en électricité par les

marchés électriques (Hogan, 2005, Joskow, 2008, Finon and Pignon, 2008, Keppler, 2014) de la même manière que cela était assuré par le monopole électrique avant la libéralisation de la plupart des systèmes électriques. De plus, cette question est renforcée par le contexte actuel où il y a une entrée massive des énergies renouvelables intermittentes telle que l'éolien ou le photovoltaique dont la production n'est pas dispatchable. Pour faire face à cet enjeux de long terme d'adéquation de capacité, différentes évolutions de l'architecture de marché ont été proposées et analysées (Pérez-Arriaga, 2001, De Vries, 2007). En particulier, il existe différents mécanismes de capacité qui se distinguent par la manière dont est fixée la rémunération de capacité, les technologies concernées et leur horizon de temps.

Chapitre 1 : Les incitations à l'investissement dans les marchés électriques libéralisés

Le premier chapitre de cette thèse analyse les points clés des systèmes électriques libéralisés puis discute certains enjeux liés à la conception des architectures de marchés. En particulier, deux problématiques majeures de l'efficacité de long terme des systèmes électriques émergent : (i) les investissements intensifs en capital dans les technologies bas-carbone et plus spécifiquement dans les énergies renouvelables et (ii) l'adéquation de capacité.

L'électricité peut être produite par différentes technologies depuis les centrales de production conventionnelles de grandes tailles jusqu'aux technologies décentralisées de plus petites capacités. Chaque technologie se caractérise par sa structure de coûts, ses contraintes techniques à respecter en temps réel et ses impacts sur l'environnement. D'un côté, les technologies thermiques conventionnelles intègrent 15% à 40% de coûts fixes, permettent une production disptachable soumise à des contraintes dynamiques et émettent généralement des gaz à effet de serre. De l'autre côté, les technologies renouvelables à production variable, telles que l'éolien ou le solaire, ont une structure de coût correspondant presque uniquement à des coûts fixes, fournissent une production non-dispatchable qui dépend des conditions météorologiques et émettent relativement peu de gaz à effet de serre par rapport aux technologies conventionnelles utilisant le gaz, le charbon ou le diesel.

En ce qui concerne la demande, la consommation d'électricité reste caractérisée par des variations significatives d'une heure à l'autre et par une faible élasticité-prix. En effet, les consommateurs de petites et moyennes tailles sont rarement sensibles aux prix horaires de l'électricité étant donné qu'ils profitent d'un tarif horaire constant (ou éventuellement deux tarifs différents avec une distinction heures creuses / heures pleines). Ainsi, leurs profils de production sont très largement expliqués par l'utilisation finale qu'ils font de l'électricité plutôt que par les prix horaires sur les marchés de gros. Sur le long terme, l'évolution de la consommation d'électricité est restée stable dans la plupart des pays de l'OCDE depuis la crise économique de 2007 et la plupart des prévisions suggérent que cette tendance va se poursuivre dans les années à venir (IRENA, 2014, NREL, 2015). En conséquence, les systèmes électriques de la majorité des pays de l'OCDE font désormais face à un contexte mature où la croissance de la demande életricque reste limitée et où les centrales de production sont déjà anciennes.

La coordination des systèmes électriques libéralisés s'appuie essentiellement sur une combinaison de marchés. Plus particulièrement, le marché day-ahead est supposé fournir le signal de long terme pour les investissements afin de garantir un niveau de capacité installée satisfaisant ainsi qu'un mix de production compatible avec les objectifs environnementaux. Pour cela, il existe généralement des politiques environnementales et climatiques qui mettent en place des mécanismes spécifiques pour orienter les choix technologiques afin d'atteindre les objectifs environnementaux fixés.

En ce qui concerne le signal de long terme pour les investissements, plusieurs défaillances du modèle de marché energy-only sont identifiées dans la littérature parmi lesquelles les plus citées sont (i) l'existence explicite ou implicite de cap de prix qui empêchent les prix de l'énergie d'atteindre les valeurs élevées nécessaires pour l'adéquation de capacité, (ii) l'aversion au risque et l'information imparfaite qui peuvent limiter les investissements dans les centrales de pointes ou les technologies bas-carbone and (iii) le caractère discret des investissements qui complique l'atteinte de l'équilibre théorique de long terme. Face à ce contat, les débats actuels portent notamment sur les pistes d'amélioration de l'adéquation de capacité des systèmes électriques et sur le développement des sources d'énergie bas-carbone en lien avec les enjeux environnementaux (Finon and Roques, 2013).

Cette thèse porte sur des questions de recherches qui émergent de cette situation. Premièrement, le développement des sources d'énergie bas-carbone ou renouvelable est actuellement favorisé par des politiques environnementales et climatiques spécifiques pour plusieurs raisons parmi lesquelles la diversification des sources d'énergie, l'indépendance énergétique et les enjeux climatiques. Les signaux de long terme n'étant pas suffisant pour permettre le développement des ces technologies intensives en capital, des mécanismes de support spécifiques sont généralement mis en place au niveau national. Cependant, ces mécanismes peuvent perturber encore davantage les signaux provenant des marchés électriques en diminuant les prix (sour l'effet de l'ordre de mérite) et en augmentant l'incertitude sur le niveau de développement de ces technologies dans le futur. Ainsi, plusieurs institutions politiques et académiques défendent le passage à des instruments de marché pour le développement des sources d'énergie bas-carbone et renouvelables (Hiroux and Saguan, 2010, Batlle et al., 2012, European Commission, 2015). Dans ce contexte, le développement par le marché de ces sources d'énergie demande d'être analysé en détail.

Deuxièmement, sur le long terme, l'adéquation de capacité des systèmes électriques libéralisés qui est théoriquement assurée par le modèle de marché energy-only continue de soulever des doutes. Face à cela, des mécanismes de capacité sont proposés afin de compléter le modèle energy-only dans sa fonction de coordination (De Vries, 2007, Finon and Pignon, 2008, Cramton et al., 2013, Keppler, 2014). De plus, l'augmentation de la part des énergies renouvelables intermittentes ajoute des nouveaux enjeux quant à l'adéquation de capacité des systèmes électriques en transition énergétique puisque cela vient modifier le profil de la demande nette addressée aux technologies conventionnelles dispatchables.

Finalement, les systèmes électriques actuels s'appuient généralement sur une combinaison de marchés et de mécanismes aditionnels spécifiquement mise en place pour répondre à des enjeux tels que le développement des sources d'énergie bas-carbone et renouvelables ou encore l'adéquation de capacité, dans le contexte de la transition énergétique. Après avoir été identifiés dans ce premier chapitre portant sur la coordination de long terme des marchés électriques libéralisés, l'étude de ces deux enjeux nécessite une modélisation adaptée des décisions d'investissement.

Chapitre 2 : La modélisation des décisions d'investissement dans production d'électricité

Dans les marchés électriques libéralisés, l'évaluation économique des projets de production d'électricité s'appuie sur les anticiations du futur faites par l'investisseur et les incertitudes qui s'y rapportent, ainsi que sur le choix d'un taux d'actualisation. Les décisions d'investissement sont basées sur différents critères d'investissement parmi lesquels la Valeur Actuelle Nette (VAN) et le Taux de Rentabilité Interne (TRI). De plus, l'évaluation et la gestion du risque prennent un rôle de plus en plus important pour les investisseurs privés étant donné les incertitudes inhérantes au secteur électrique. Les incertitudes et les risques peuvent être analysés selon différentes approches parmi lesquelles l'utilisation de fonctions d'utilité, l'analyse moyenne-variance (liée à la théorie du portefeuille) ou encore le taux d'actualisation ajusté en fonction du risque. Finalement, la modélisation des décisions privées d'investissements doit prendre en compte certains éléments clés (Botterud, 2003) : (i) un processus cohérent avec les décisions décentralisées dans les marchés électriques libéralisés, (ii) les différentes échéances du projet d'investissement y compris les délais de construction des équipements et (iii) les incertitudes de long terme.

En pratiques, différentes approches permettent de modéliser les systèmes électriques. Il est possible d'identifier trois familles principales : les modèles d'optimisation, les modèles microéconomiques d'équilibre et les modèles de simulation (Ventosa et al., 2005). Ces modèles permettent de s'intéresser aux investissements dans les marchés électriques avec différents points de vue. Parmi ces approches, la modélisation en System Dynamics (SD), qui fait partie des modèles de simulation, est particulièrement adaptée pour étudier l'évolution temporelle du mix de production d'électricité résultant des décisions d'investissement par des acteurs privés. En effet, la modélisation SD permet de représenter un processus d'investissement qui se base sur des critères économiques utilisés par les investisseurs privés en considérant des hypothèses de rationalité limité, des incertitudes de long terme et en représentant les délais de construction des équipements.

The Simulator of Investment Decisions in the Electricity Sector (SIDES)

Développé entièrement dans le cadre de ce projet et s'appuyant sur la modélisation SD, le modèle SIDES (Simulator of Investment Decisions in the Electricity Secor) permet de simuler l'évolution du mix de production sur plusieurs dizaines d'années. Pour cela, le modèle représente un investisseur caractéristique évoluant dans différentes architectures de marchés : le marché energy-only de référence mais aussi l'ajout d'un mécanisme de capacité. Le modèle SIDES propose une réprésentation des nouveaux investissements mais aussi des décisions de fermetures anticipées pour un ensemble de technologies de production conventionnelles et renouvelables. La modélisation détaillée des marchés électriques horaires en compétition parfaite et la prise en compte de plusieurs scénarios météorologiques permet d'étudier les systèmes électriques comportant des sources d'énergie renouvelables à production variable.

Le modèle SIDES est particulièrement adapté à l'étude des dynamiques de long terme des systèmes électriques libéralisés puisqu'il permet de modéliser les traits principaux des investisseurs privés : (i) décisions basées sur des critères économiques avec une prise en compte de l'aversion au risque, (ii) hypothèse de myopie quant à l'anticipation du futur, (iii) prise en compte des délais entre le moment de la décision et l'arrivée en service des nouveaux moyens de production et (iv) la représentation des décisions de fermeture des centrales existantes avant leur arrivée en fin de vie si celles-ci apparaissent comme non rentables. La figure F.1 présente le schéma simplifié du modèle.

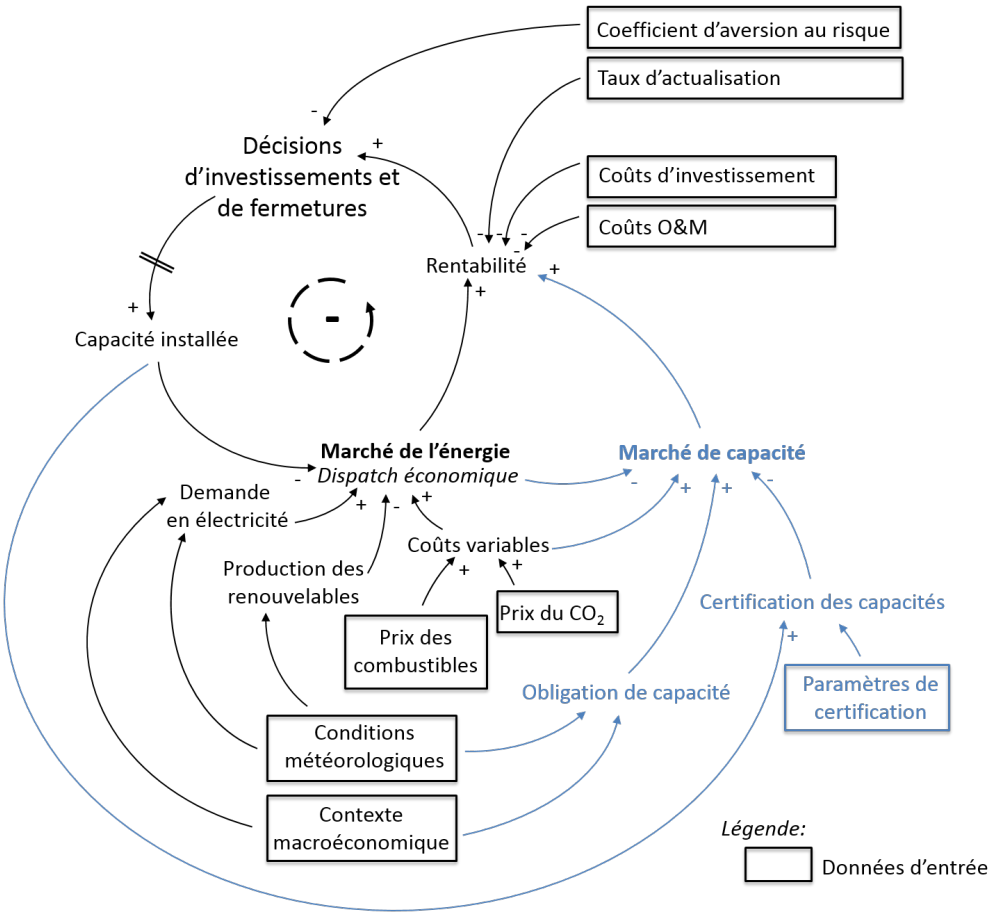


FIGURE F.1: Diagramme représentant le fonctionnement du modèle SIDES.

Chapitre 3 : Le développement de l'éolien sans mécanisme de soutien

La réduction des émissions de gaz à effet de serre est l'un des objectifs des politiques énergétiques actuelles. Pour cela, différents intruments politiques peuvent être mis en place comme par exemple des subventions pour les énergies bas-carbone, des normes d'émissions ou encore l'ajout d'un prix du carbone qui viendra se refléter dans les coûts variables de production de l'électricité. Ainsi, cela conduit à identifier deux régimes d'investissement pour les projet de production d'électricité : (i) l'un basé sur le signal d'investissement envoyé par les prix de marché, l'anticipation de la valeur nette et l'utilisation de critères économiques et (ii) l'autre relevant de mécanismes hors-marché s'appuyant sur des accords de long terme permettant une subvention de certaines technologies associée à un transfert de risque vers les consommateurs via un levier de financement des ces politiques. De plus, à l'heure actuelle, il y a une coéxistence de mécanismes

de soutien des énergies renouvelables et l'application d'un prix du carbone (EU Emissions Trading System) dans la plupart des pays européens. Dans ce contexte, il semble maintenant nécessaire de remettre en cause ces mécanismes de soutien spécifiques. La question qui se pose alors consiste à estimer dans quelle mesure le développement des énergies renouvelables pourrait émerger grâce à la seule présence d'un prix du carbone permettant d'internaliser les externalités environnementales de l'activité de production d'électricité.

Ce troisième chapitre s'intérèsse donc à estimer le developpment potentiel de l'éolien[1] par les marchés électriques en supposant la mise en place d'un prix du carbone mais sans l'ajout de mécanismes de soutien. Différents prix du carbone sont testés afin de déterminer à partir de quel niveau des investissements dans l'éolien peuvent être déclenchés par le seul marché de l'énergie. Ce chapitre s'appuie très largement sur un article publié[2].

Méthodologie et présentation du cas d'étude

Le modèle SIDES développé dans le cadre de cette thèse est utilisé pour simuler les décisions d'investissement sur une durée de vingt ans en partant d'un parc initial comprenant uniquement des moyens thermiques. Le cas d'étude est conduit sans aversion au risque et sans mécanisme de capacité. Les technologies considérées sont : les centrales au gaz, les centrales au charbon, les centrales de pointe et l'éolien terrestre. Dans un second temps, l'effet du nucléaire est également estimé. La consommation d'électricité est supposée constante sur l'ensemble de la période simulée grâce à des efforts d'efficacité énergétique.

Résultats principaux

Sur la base des hypothèses de coûts considérées pour les différentes technologies de production, les simulations réalisées avec le modèle SIDES (voir figure F.2) montrent que, dans un système sans nucléaire, le développement de l'éolien par le marché est rendu possible à partir d'un prix du carbone de 70 €/tCO_2. Pour les prix du carbone élevés

[1] L'éolien est choisi comme un exemple de technologie renouvelable relativement mature quant à sa commercialisation et son exploitation.

[2] Petitet, M., Finon, D., and Janssen, T., 2016. Carbon price instead of support schemes: Wind power investments by the electricity market. *The Energy Journal*, 37(4):109-140.

(au dessus de 70 €/tCO_2), le développement de l'éolien s'accompagne d'autres effets endogènes clairement identifiables dans les simulations : (i) la diminution de la capacité thermique totale, (ii) le remplacement progressif des centrales au charbon par des centrales au gaz sous l'effet du changement d'ordre de mérite imposé par l'augmentation du prix du carbone et (iii) la stabilisation de la capacité éolienne en fin de simulation expliquée par la cannibalisation de la valeur économique de l'éolien par son propre développement. Sur les marchés de l'électricité, il est également possible d'observer deux effets principaux : (i) l'augmentation des prix de marché lorsque le prix du carbone augmente d'une simulation à l'autre et (ii) la diminution des prix de marché au cours des vingt ans simulés en conséquence de l'augmentation de la part de l'éolien. Concernant le fonctionnement du système électrique, le développement de l'éolien entraine une augmentation du nombre d'heures où la production n'est pas suffisante pour couvrir la demande (à cause de la variabilité de l'éolien et de la diminution de la capacité thermique) mais aussi une augmentation du nombre d'heure où une partie de l'énergie produite par les éoliennes est déversée pendant les moments de faible consommation. Ces deux effets combinés suggèrent que le stockage pourrait jouer un rôle dans la diminuation de ces évènements dans un système réel.

De plus, ce cas d'étude permet également d'illustrer la différence qu'il exstime entre l'approche par le coût complet de l'électricité et la modélisation des investissements via des critères de rentabilité économique. En effet, le prix de carbone qui permet de déclencher des investissements dans l'éolien observé dans les simulations avec le modèle SIDES est significativement supérieur au prix du carbone qui assure l'équivalence entre le coût complet de l'éolien et celui des autres technologies considérées.

Dans un deuxième temps, le nucléaire est ajouté afin d'estimer son effet sur le développement de l'éolien. Les simulations mettent en avant que le nucléaire complique très significativement le développement de l'éolien. Cela s'explique par le fait que, de façon similaire à l'éolien, cette technologie bénéficie d'un coût variable qui ne dépend pas du prix du carbone mais que, contrairement à l'éolien, la production des centrales nucléaires est dispatchable. Ainsi, en présence du nucléaire, aucun développement de l'éolien n'est observé pour des valeurs du prix de carbone en dessous de 150 € /tCO_2, même si l'on ajoute comme contrainte de ne pas investir dans de nouvelles centrales nucléaires au cours de la période simulée.

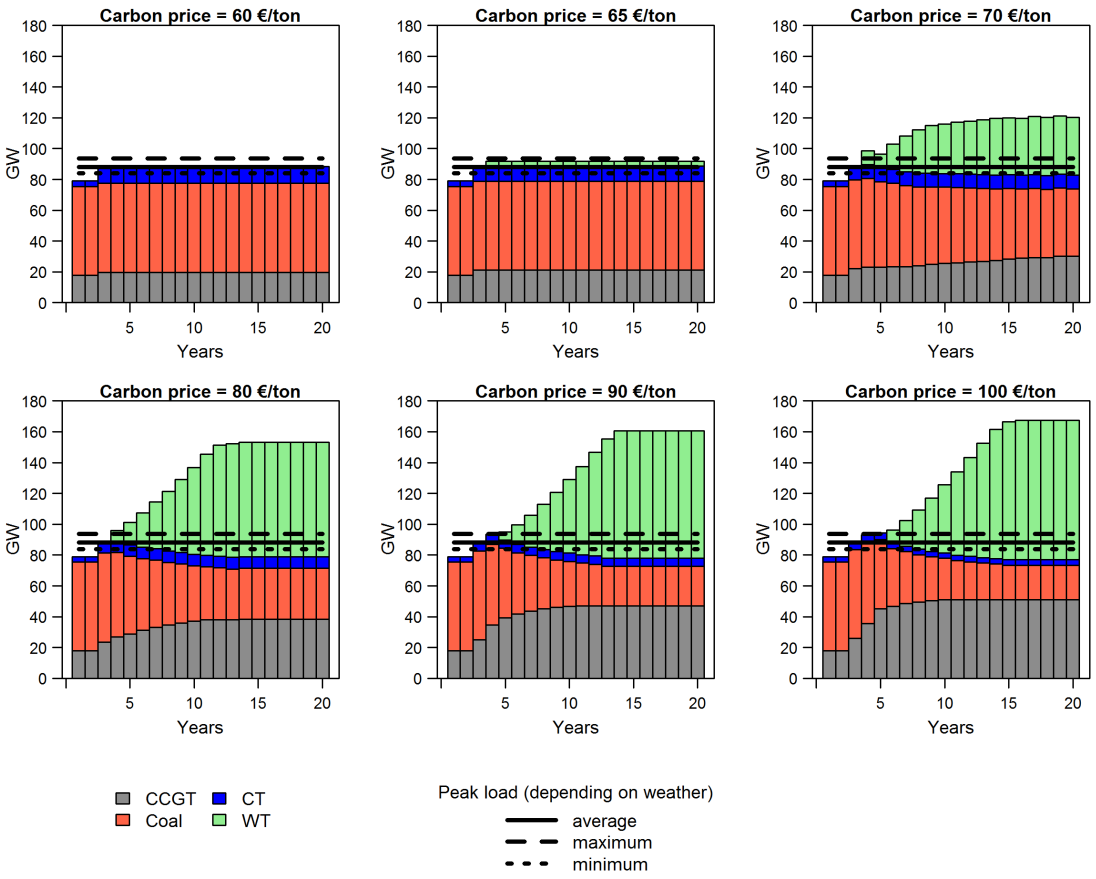


FIGURE F.2: Evolution de la capacité installée (GW) pour différents prix du carbone pour le cas d'étude sans nucléaire.

Finalement, l'étude présentée dans le troisième chapitre de cette thèse permet de conclure que la transition vers des investissements basés sur les prix de marché en présence d'un prix du carbone sans aucun autre mécanisme de soutien pour les technologies renouvelables semble possible qu'à condition d'un engagement politique fort en faveur d'un prix du carbone élevé.

Chapitre 4 : Améliorer la sécurité d'approvisionnement en électricité par un mécanisme de capacité

Le modèle de référence energy-only, un niveau socialement acceptable de capacité est supposé émergé des investissements réalisés sur le seul signal envoyé par les marchés horaires où le prix se fixe au coût marginal du dernier moyen de production. Ce modèle est

remis en question concernant la garantie de l'adéquation de capacité des systèmes électriques libéralisés (Hogan, 2005, Joskow, 2008, Finon and Pignon, 2008, Keppler, 2014). De plus, à cette question s'ajoute le contexte actuel caractérisé par une entrée massive des énergies renouvelables intermittentes telle que l'éolien ou le photovoltaique dont la production n'est pas dispatchable. Pour faire face à cet enjeu de long terme d'adéquation de capacité, différentes évolutions de l'architecture de marché ont été proposées et analysées (Pérez-Arriaga, 2001, De Vries, 2007). En particulier, il existe différents mécanismes de capacité qui se distinguent par la manière dont est fixée la rémunération de capacité, les technologies concernées et leur horizon de temps.

Dans ce contexte, le quatrième chapitre de cette thèse s'intéresse à la question de l'adéquation de capacité de production en s'appuyant sur une analyse des systèmes électriques matures soumis à des politiques de transition énergétique. Ce chapitre s'appuie sur un document de travail[3] et sur un article de conférence[4] qui prend en compte l'aversion au risque des investisseurs.

Méthodologie et présentation du cas d'étude

L'anlalyse proposée dans ce chapitre s'appuie sur des simulations réalisées avec le modèle SIDES. L'étude s'intérèsse à un système électrique mature en transition énergétique, caractérisé par un développement significatif des énergies bas-carbone et en particuliar des énergies renouvelables combiné à une demande électrique stable sous l'effet de mesures d'efficacité énergétique. En s'appuyant sur deux scénario de transition énergétique, l'objectif est de quantifier comment différentes architectures de marchés peuvent améliorer l'adéquation de capacité des systèmes électriques et le bien-être social qui en résulte. Les architectures de marché étudiées sont: (i) le modèle de référence energy-only avec un plafond de prix fixé à 3 000 €/MWh (noté EOM3) comme c'est actuellement le cas sur EpexSpot, (i) un marché energy-only avec scarcity pricing (noté EOM20) où le prix horaire atteint 20 000 €/MWh lorsque la consommation excède la production et enfin (iii) un marché de l'énergie avec plafond de prix fixé à 3 000 €/MWh combiné

[3] Petitet, M., Finon, D., and Janssen, T., 2016. Ensuring capacity adequacy during energy transition in mature power markets: A social efficiency comparison of scarcity pricing and capacity mechanism. CEEM Working Paper n°20.

[4] Petitet, M., 2016. Effects of risk aversion on investment decisions in electricity generation: What consequences for market design? In Proceedings of the 13th International Conference on the European Energy Market.

à l'ajout d'un marché annuel de capacité (noté CM) pour l'ensemble des capacités de production.

De plus, dans les marchés électriques libéralisés, les investisseurs privés font face à des incertitudes significatives sur l'évolution de long terme de l'offre et de la demande. Ainsi, la prise en compte de l'aversion au risque dans le processus de décisions peut avoir pour conséquence de diminuer le niveau de capacité installée éloignant donc le système électrique réel de l'optimum social de façon plus ou moins marquée en fonction de l'architecture de marché. Pour cette raison, l'analyse est réalisée en prenant en compte l'aversion au risque des investisseurs via l'introduction d'une fonction d'utilité. Plusieurs niveaux d'aversion au risque sont simulés afin de quantifier l'effet de ce paramètre sur l'adéquation de capacité résultant des différentes architectures de marché considérées.

Résultats principaux

L'analyse réalisée sur la base de simulations avec le modèle SIDES font émerger trois types de conclusion. Premièrement, le modèle energy-only avec plafond de prix fixé à 3 000 €/MWh ne permet pas d'assuer un niveau d'approvisionnement en éléctricité sociallement acceptable. Le niveau d'averion au risque influence de façon négative l'adéquation de capacité résultant de cette architecture de marché.

Deuxièmement, les architecures de marchés alternatives (déplafonnement du prix horaire ou ajout d'un mécanisme de capacité) améliorent fortement l'adéquation de capacité et le bien-être social qui en résulte comme illustré dans les figures F.3 et F.4 (EOM20 et CM à comparer à EOM3).

Troisièmement, le niveau d'aversion au risque des investisseurs privé influence significativement le bien-être social obtenus pour les différentes architectures de marché simulées (voir figures F.3 et F.4). Lorsque le niveau d'aversion au risque est élevé ($\alpha = 3$), l'ajout d'un mécanisme de capacité apparait comme la meilleure solution parmi les différentes architectures de marché considérées. Finalement, cette analyse souligne l'importance de la prise en compte de l'aversion au risque dans l'évaluation et le choix d'une architecture de marché.

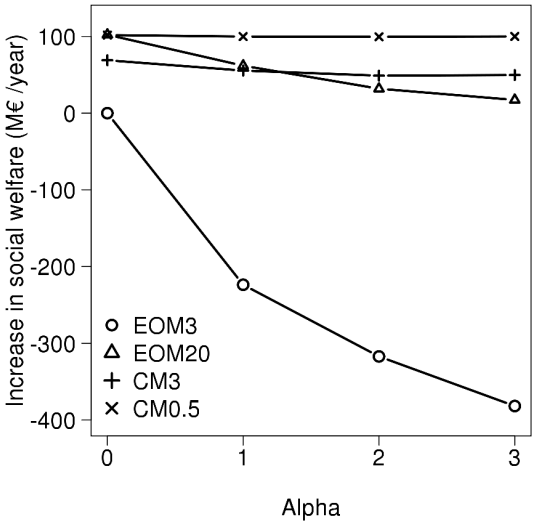


FIGURE F.3: Variation du bien-être social par rapport au modèle de référence energ-only avec prix-plafond sans aversion au risque, pour le premier scénario de transition énergétique.

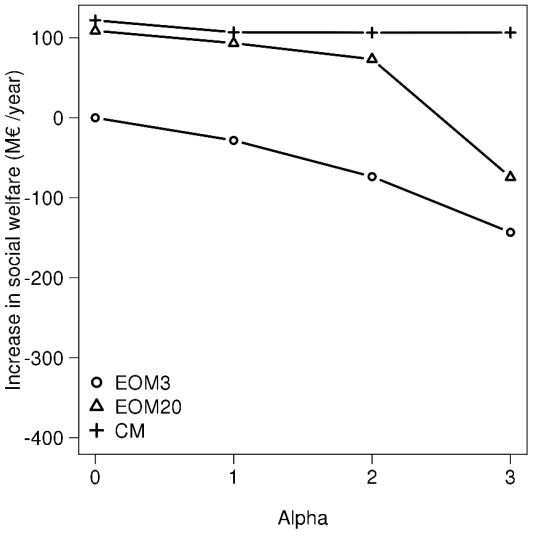


FIGURE F.4: Variation du bien-être social par rapport au modèle de référence energ-only avec prix-plafond sans aversion au risque, pour le deuxième scénario de transition énergétique.

Conclusion

Cette thèse analyse la coordination de long terme des marchés électriques libéralisés en s'intéressant à deux problématiques que sont le développement des énergies renouvelables sans mécanisme de soutien et l'amélioration de l'adéquation de capacité. Ces enjeux sont étudiés dans le cadre de marchés électriques matures soumis à des politiques de transition énergétique. Le cadre méthodologique proposé s'appuie sur un modèle de simulation en System Dynamics qui reflète le procecuss de décision des investisseurs privés.

Concernant le développement des énergies renouvelables, les résultats montrent que les signaux de marchés peuvent déclencher des investissements dans les technologies renouvalables intermittentes à condition d'un engagement politique fort permettant la mise en place d'un prix du carbone élevé.

Concernant l'amélioration de l'adéquation de capacité des systèmes électriques matures en transition énergétique, les résultats mettent en évidence l'insuffisance du modèle energy-only pour assurer cette fonction de coordination de long terme. L'ajout d'un marché de capacité ou la suppression du plafond de prix permettent une amélioration en termes de nombre d'heures de délestage et de bien-être collectif. De plus, en considérant deux scénarios de transition énergétique et plusieurs hypothèses sur l'aversion au risque

des investisseurs privés, le marché de capacité apparaît comme le meilleur choix pour le régulateur parmi les architectures de marché considérées.

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Résumé

Les marchés électriques libéralisés sont supposés assurer la coordination de long-terme des investissements afin de garantir sécurité d'approvisionnement, viabilité et compétitivité. Dans le modèle de référence energy-only, la tarification au coût marginal des marchés électriques fournit un signal prix pour les investisseurs. Cependant, en pratique, ce modèle est remis en question quant à sa capacité à déclencher des investissements dans les technologies bas-carbone et en particulier les énergies renouvelables (EnR) et quant à sa capacité à garantir la sécurité d'approvisionnement.

Après avoir caractérisé ces défaillances de marché, cette thèse s'intéresse à différentes solutions en s'appuyant sur un modèle en System Dynamics développé afin de simuler les investissements dans les marchés électriques.

Les résultats montrent que le remplacement des mécanismes de support hors marché par des investissements par le marché avec l'aide d'un prix du carbone apparait comme une solution pour déclencher le développement des EnR à condition d'un engagement politique fort en faveur d'un prix du carbone élevé.

Il apparait aussi que le marché energy-only avec des prix plafonnés ne parvient pas à assurer l'adéquation de capacité dans un contexte de marchés électriques matures avec des centrales thermiques conventionnelles faisant face à des scénarios de transition énergétique. L'ajout d'un marché de capacité ou la suppression du plafond de prix permettent une amélioration en termes de nombre d'heure de délestage et de bien-être collectif. En considérant deux scénarios de transition énergétique et plusieurs hypothèses sur l'aversion au risque des investisseurs, le marché de capacité apparaît comme le meilleur choix pour le régulateur parmi les architectures de marché considérées.

Mots Clés

Marchés électriques, Investissements, Énergies renouvelables, Adéquation de capacité, Modélisation en System Dynamics.

Abstract

In liberalised electricity systems, power markets are expected to ensure the long-term coordination of investments in order to guarantee security of supply, sustainability and competitiveness. In the reference energy-only market, it relies on the ability of power markets — where the hourly price is aligned with the marginal cost of the system — to provide an adequate price-signal for investors. However, in practice, questions have been raised about its ability to trigger investments in Low-Carbon Technologies (LCT) including in particular Renewable Energy Sources of Electricity (RES-E), and its ability to ensure capacity adequacy.

After a characterisation of these market failures, this dissertation tackles the two research topics of RES investments and capacity adequacy within a methodological framework based on a System Dynamics model developed to simulate private investment decisions in power markets.

First, the results show that substituting out-of-market support mechanisms for RES-E by market-based investments helped by the sole implementation of a carbon price appears as a feasible solution to trigger RES-E development providing that there is a political commitment on a high carbon price.

Second, it also appears that the energy-only market with price cap is ineffective to ensure capacity adequacy in a context of mature markets with conventional thermal power plants under transition paths. Adding a capacity market or removing the price cap both bring benefits in terms of Loss Of Load Expectation (LOLE) and social welfare. Moreover, considering two various energy transition scenarios and different assumptions about the risk aversion of private investors, the capacity market is identified as the best option among the considered market designs.

Keywords

Electricity markets, Investments, Renewables energy sources, Capacity adequacy, System Dynamics modelling.