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Arthur Henriot

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Economics of intermittent renewable energy sources: four essays on large-scale integration into European power systems

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# ABSTRACT

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This thesis centres on issues of economic efficiency originating from the large-scale development of intermittent renewable energy sources (RES) in Europe. The flexible resources that are necessary to cope with their specificities (variability, low-predictability, site specificity) are already known, but adequate signals are required to foster efficient operation and investment in these resources. A first question is to what extent intermittent RES can remain out of the market at times when they are the main driver of investment and operation in power systems. A second question is whether the current market design is adapted to their specificities. These two questions are tackled in four distinct contributions.

The first chapter is a critical literature review. This analysis introduces and confronts two (often implicit) paradigms for RES integration. It then identifies and discusses a set of evolutions required to develop a market design adapted to the large-scale development of RES, such as new definitions of the products exchanged and reorganisation of the sequence of electricity markets.

In the second chapter, an analytical model is used to assess the potential of intraday markets as a flexibility provider to intermittent RES with low production predictability. This study highlights and demonstrates how the potential of intraday markets is heavily dependent on the evolution of the forecast errors.

The third chapter focuses on the benefits of curtailing the production by intermittent RES, as a tool to smooth out their variability and reduce overall generation costs. An analytical model is employed to anatomize the relationship between these benefits and a set of pivotal parameters. Special attention is also paid to the allocation of these benefits between the different stakeholders.

The fourth chapter evaluates in a numerical simulation the ability of the European transmission system operators (TSOs) to finance the wave of investments required to manage the development of intermittent RES. Alternative financing strategies are then assessed. The findings reveal that under the current trend of tariffs, the volumes of investment forecasted will be highly challenging for TSOs.

# ACKNOWLEDGEMENTS

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# INTRODUCTION

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## 1 Background

### 1.1 The growing share of intermittent RES in European power systems

European power systems feature an increasingly significant share of electricity generated by renewable energy sources (hereby 'RES'). This development results from a wide range of preoccupations including Climate Change mitigation, reducing dependency on fossil fuel imports, or creating a national industry. While not all RES are intermittent, the main potential resources in Europe feature intermittency (wind turbine and photovoltaic panels). As a result of the Directive on the promotion of the use of energy from renewable sources<sup>1</sup>, there are already national power systems coping with a large share of intermittent RES. If the national targets imposed by the directive are to be met, capacity penetration of intermittent RES could be close to 100% of peak demand in 2020 in some member states. This is the case of Germany, Portugal, Spain, or Ireland (Figure 1). The purpose of this thesis is not to discuss the relevance of such targets. We will focus instead on the integration of an increasingly important share of intermittent RES into power systems.

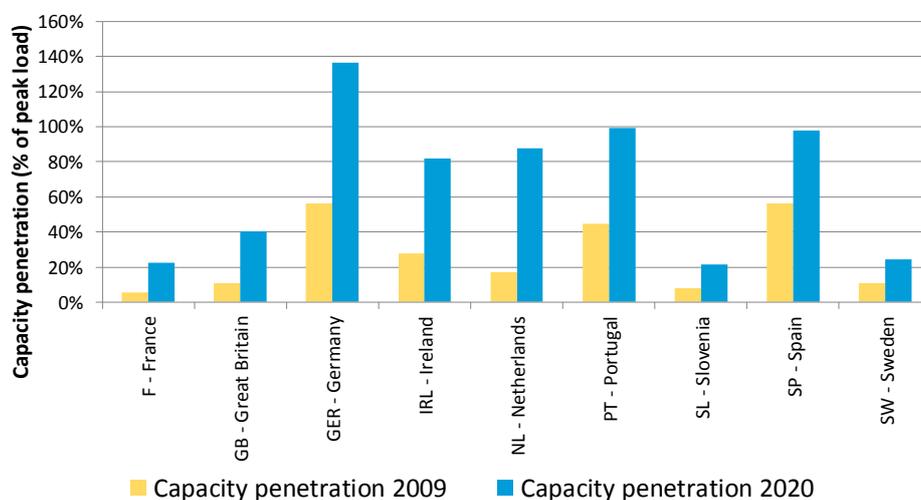


Figure 1: Capacity penetration of intermittent RES (Source: Henriot et al., 2013)

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<sup>1</sup> Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009

Before getting into details, it is important to point out that “intermittency<sup>2</sup>” is not specific to RES. Existing generation units are subject to unexpected forced outages and none are able to operate 100% of the year or with an absolute certainty of delivering when committed. Power systems are also used to cope with the variability and uncertainty of the demand side. However, the output of the bulk of traditional generation is controllable with relatively low failure rates and demand fluctuations are reasonably predictable and change relatively slowly. Despite not being a new phenomenon, the variability and uncertainty introduced by intermittent RES into power systems create additional challenges due to the size and the difficulty in predicting changes.

## 1.2 Technical features of intermittent RES

In this section we focus on three technical characteristics of intermittent RES which are relevant to the integration of large-scale RES: output variability, the difficulties in forecasting this output accurately, and the fact that RES output often depends on local resources (“site-specificity”). Further information can be found in Henriot, A. et al. (2013).

### ***Variability***

Wind doesn’t always blow, sun doesn’t always shine. As a result wind power and solar power fluctuate over time. Fluctuations are seasonal, daily, hourly or minute-by-minute and affect power systems in different ways.

#### Short-term variability

Fast fluctuations can occur within seconds or within minutes. Several studies have demonstrated that these fast fluctuations do not constitute a significant burden for the system operator and can be handled by traditional methods used to manage load fast variability (Fruent, 2011). Moreover, very short-term variations (within seconds) tend to statistically average out when intermittent RES penetration increases.

---

<sup>2</sup> The term “variable” is sometimes considered as more appropriate than “intermittent” (See for instance the 2010 NREL paper by Milligan and Kirby). Intermittent implies something that rapidly cuts in and out of availability, whereas solar and wind generation generally vary more gradually over longer timescales. “Variable” captures the nature of this behaviour more accurately. However, the term “intermittent” has become common and will be used in this thesis.

Longer-scale variations occur over a period of several minutes to several hours. The range of these variations can be quite high as illustrated in Table 1. Yet it can be noticed in this table that even at times of extreme weather events wind production never switches completely or instantaneously.

			10-15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Nr of sites	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase
Denmark	300×300 km <sup>2</sup>	>100			-23%	+20%	-62%	+53%	-74%	+79%
- West Denmark	200×200 km <sup>2</sup>	>100			-26%	+20%	-70%	+57%	-74%	+84%
- East Denmark	200×200 km <sup>2</sup>	>100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280×480 km <sup>2</sup>	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300×800 km <sup>2</sup>	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400×400 km <sup>2</sup>	>100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400×900 km <sup>2</sup>	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400×900 km <sup>2</sup>	56			-17%	+19%	-40%	+40%		
US Midwest	200×200 km <sup>2</sup>	3	-34%	+30%	-39%	+35%	-58%	+60%	-78%	+81%
US Midwest+ Oklahoma	1200×1200 km <sup>2</sup>	4	-26%	+27%	-31%	+28%	-48%	+52%	-73%	+75%

**Table 1: Extreme variations of large scale regional wind power as % of installed capacity (Holtinnen 2009)**

Some modern wind turbines are designed to curtail production when wind speeds exceed a certain threshold, in order to protect the wind turbines. This leads to a situation where the production of individual turbines suddenly switches from peak production to zero (see Figure 2). However this effect will be distributed in time across a wind farm (the entire wind farm will not instantaneously switch from peak to zero), and across a region. This means that it will occur more slowly than the sudden forced outage of a large thermal unit (for example), and will likely be more predictable (via wind forecasts).

Long-term variability

There are also climatic seasonal effects affecting intermittent RES. The output from solar photovoltaic panels will typically be lower during the winter while average wind farm output may also vary with season. This phenomenon is less challenging from a system security point of view but it means additional plants may be needed to cope with these effects, especially if periods of low generation coincide with periods of high demand. It therefore can constitute a challenge for generation adequacy.

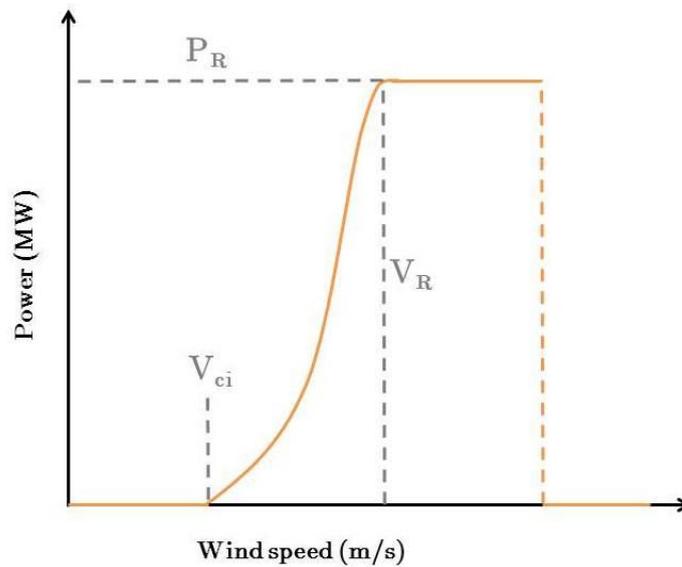


Figure 2: Typical transfer function of a wind turbine.  $V_{ci}$  is the cut-in wind speed; for wind speed higher than  $V_R$  the wind is spilled by feathering the blades (Söder, 2002) .

### Smoothing factors

For a given technology, *geographical spread* can result in much lower variability on a system-scale. The more units and the less correlated their production, the less variable the total output, as illustrated in Figure 3. Even in small systems such as Denmark, significant stability gains are achieved when comparing the system as a whole to each wind farm independently. Extreme weather events nevertheless occur on significant geographical scales (> 1000 km) that can therefore affect entire large systems at the same time.

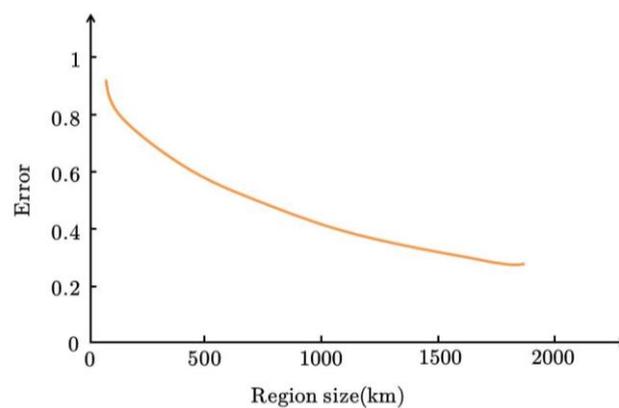


Figure 3: Decrease of forecast error for aggregated wind power prediction, based on data from 40 wind farms in Germany (Holtinen et al., 2009)

Significant gains can also be obtained from *technological spread*. When PV panels output and wind farms output are negatively correlated, their combined output is much steadier.

The correlation between demand and intermittent RES variability is also an important factor. On a long-term basis, power systems typically feature a seasonal peak during the winter (due to heating) or during the summer (due to air-conditioners). This seasonal peak demand may or may not correspond to the peaks of intermittent RES output previously mentioned. Such effects can also occur on shorter time-scales: demand is for example often low at night when solar PVs are not generating. Situations can occur when load and intermittent RES generation vary in the same or opposite directions.

Using both technological spread and geographical spread, it could be possible for a given power-system to smooth variations by adopting a risk-portfolio approach such as that proposed by Roques, Hiroux, and Sagan (2010).

### ***Low-predictability***

Power systems need to forecast the conditions of real-time balancing to minimize the risk of black-outs (real-time imbalances). Depending on dynamic constraints of technologies, most thermal plants plan their production in advance as they have limited flexibility whereas some others get the capability to start/stop very quickly. Intermittent RES technologies, wind being the typical example, depend on very complex physical phenomenon. It is therefore difficult to accurately forecast what will be the exact contribution of these plants in real-time. Hence imbalances between the forecasted and actual production can occur at the system-scale which can lead to global imbalances and the need to use flexible and reliable dispatchable plants (mostly thermal units and large hydro) to ensure the real-time balancing of supply and demand.

System Operators are used to managing uncertainties in power systems, as load is also not perfectly predictable. Maupas (2008) estimated that the Mean Square Error (MSE) of load in France would be roughly the same as that resulting from 15 GW of installed wind power. However he also argued that errors in consumption were much more regular and therefore easier to correct. This is partly due to phase errors specific to wind forecasts (as illustrated in Figure 4) leading to forecast errors with opposite signs. The experience with demand forecasting is also quite extensive.

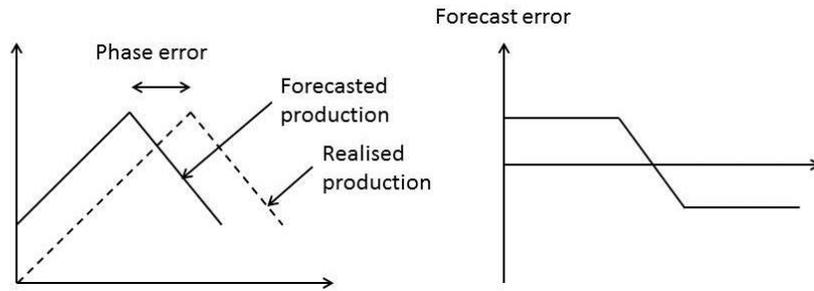


Figure 4: Impact of a phase error on forecast error (Maupas (2008))

Wind forecast tools keep improving over time as experience increases. They are generally based on physical models and meteorological data mixed with statistical models. However while they tend to do well for short-term projections (i.e. a few hours) they still face difficulties in providing accurate estimates for the day-ahead as illustrated for Germany in Figure 5. For comparison, the day-ahead Mean Square Error for the French system load during winter 2006 and 2007 was about 1% of peak consumption (Maupas, 2008).

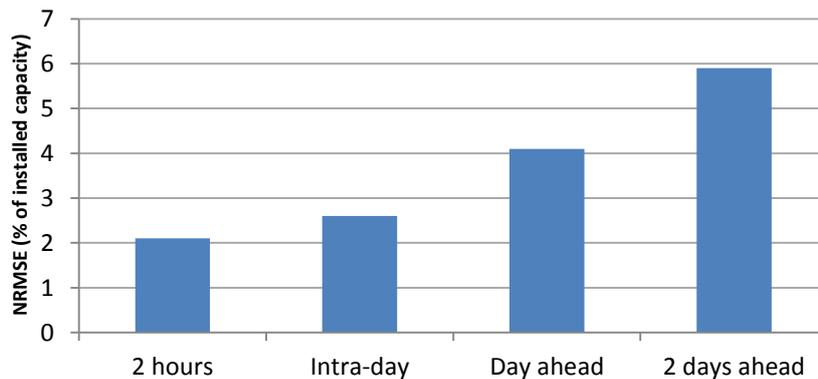


Figure 5: Wind power forecast error with increasing forecast horizon (2009 average value in Germany, from Tambke as quoted by EWEA (2010))

As for variability, the forecast errors of several wind farms can self-compensate and the average error is lower for larger systems or large portfolios. Aggregation of wind farms is therefore useful for managing short-term uncertainty.

### Site specificity

Wind properties vary a lot geographically, including at a national scale. Solar resource quality also depends a great deal on latitude. The best resources are generally geographically concentrated and sometimes far from the existing grid. In the UK the best wind resources are located in Scotland; to access these resources the network must connect these areas to consumption centres in the south of England. The pattern is similar

in Germany. Furthermore, intermittent RES are often land-intensive. As a result, the higher land prices closer to load centres are another constraint to be taken into account.

A trade-off is hence to be faced between building at the best generation sites and minimising transmission costs. This is exacerbated by the fact that the load factor of a wind farm is typically low, meaning that it will often be inefficient to build enough transmission capacity to carry the full installed capacity of the wind farm. It is necessary to handle these dilemmas in a cost-efficient way, which can be made easier by appropriate connection tariffs and procedures.

Finally, the variability of intermittent RES output can result in significant variations in network flows. These flows can impact neighbouring power systems; for example, electricity generated in the North of Germany results in parallel flows through Poland and the Czech Republic.

## **2 Research scope**

In power systems, supply must always match demand instantaneously so as to avoid a general failure of the system. Therefore, some back-up flexible resources must be available to compensate both expected and unexpected variations of demand or generation. While variability and low-predictability are traditional features of power systems, the large-scale development of intermittent renewable energy sources (hereby 'RES') introduces higher flexibility needs that must be met by a smaller number of dispatchable power plants.

In Europe, an increasingly important share of the electricity generation mix is provided by intermittent RES such as wind turbines and photovoltaic panels. They are isolated from market signals by priority schemes and support mechanisms. In addition, intermittent RES feature by definition specificities that challenge the operation of power systems. First, the amount of energy generated by these units varies significantly with the availability of natural resources they depend on. Second, their production is not perfectly predictable.

All along this thesis, we consider that the nature of these issues is not a technical one, but a question of economic efficiency. In other words, many technologies of flexible resources required to deal with the specific features of intermittent RES are already known, but adequate economic incentives still have to be investigated to foster efficient operation and investment in these resources. Under the current European framework, the signals required to ensure efficient operation of the power systems must be delivered through a set of electricity market arrangements coordinating the participants from the day-ahead

horizon to the real-time. Generation unit-commitment typically takes place in day-ahead markets, while generation imbalances between commitment and actual production are managed in balancing markets close to real-time. As new operational needs emerge, new market signals must reflect these needs, and the value of flexibility. Moreover, as more significant information regarding the amount of energy generated by intermittent RES becomes available close to real-time, the traditional emphasis on the day-ahead market also has to be reviewed.

Besides, a third specificity of intermittent RES like wind is that the best resources are often located far from demand. Significant investment in the electricity transmission network must be realised so as to connect the new production units to load centres. This is a source of high financing needs but in a context of low energy-demand growth. While the European Transmission System Operators ('TSOs') receive ex-post a regulated rate-of-return, at times of financial difficulties in Europe their ability to collect enough capital to finance these significant investments is challenged. The financeability of a grid investment wave is not granted.

Intermittent RES have as a result become an essential driver of investment and operation of power systems in Europe.

A first question to address is therefore to assess to what extent intermittent RES (being the main driver of investment and operation of power systems) can remain out of the current electricity market operation. On the one hand, Pérez-Arriaga, I. J. (2012) argues that the share of intermittent RES is reaching such levels that they cannot be considered as passive units. On the other hand, it is also sometimes argued that exposing intermittent RES to market signals to which they are not equipped to easily react will hinder their development (Batlle, C., I. J. Pérez-Arriaga and P. Zambrano-Barragán 2012, Klessmann, C., C. Nabe and K. Burges 2008).

A second question is to determine to what extent the current market design is adapted to an energy system featuring a high share of intermittent RES (Green, R. 2008, Hogan, W. W. 2010). Existing time-units of product delivery in the market might not fit highly variable generation by intermittent RES. The low-predictability of intermittent RES could challenge the key-role played today by the day-ahead market horizon in European electricity markets. More accurate locational signals could also be needed to avoid high-cost locations of RES and reduce the need for investment in the transmission network.

After an introduction in chapter 1, this thesis tackles issues related to each of the three specificities of intermittent RES: low-predictability in chapter 2, variability in chapter 3, and site specificity in chapter 4. We do this from original angles and tailor-made approaches: first a critical literature review, then two analytical models, finishing with a numerical calculation based on balance-sheet modelling. We will now enter into deeper details of our four contributions.

### **3 Research overview**

#### **3.1 On the nature of the RES integration challenge**

There is a recent but already extensive literature focusing on these questions and some of the most influential pieces of works are discussed in the critical literature review realised in **Chapter 1**.

In this chapter, we first consider to what extent intermittent resources should be treated as dispatchable resources, given their specificities. We identify two general frameworks that have emerged in the literature on integration of intermittent RES. A first one is a “melting-pot” integration, in which active intermittent RES are exposed to the same rules and rewards as dispatchable generators. A second one is a “salad bowl” integration, in which different sets of rules are applied to generators with different technological properties. Our analysis indicates that there is no fundamental obstacle to the “melting-pot” paradigm, provided a few pre-requisites are implemented.

Under both paradigms, there is a consensus among academics on the need to adapt the existing market design to the large-scale penetration of intermittent resources. First, the definitions of the products exchanged in the market should evolve to reflect new needs: time-unit and space-unit of product delivery and price boundaries must be adapted to more volatile generation patterns. Second, the traditional sequence of electricity markets (from day-ahead to real time) will be challenged, as low-predictability will lead more exchanges to take place closer to real-time.

This chapter is joint work with Prof. Jean-Michel Glachant and has been published in *Utilities Policy*, Volume 27, December 2013, pages 57-64.

#### ***On redesigning the sequence of markets: the case of intraday markets***

Generation by intermittent RES is not predictable with a sufficient precision, and forecasts improve significantly up to a few hours before the production time. As a consequence, the key-role played today by the day-ahead market does not match all the needs of market

participants. Significant volumes of exchanges will take place after the day-ahead, in the balancing market as a last resort, or in an intraday market taking place between day-ahead and real-time. This demonstrates how the sequence of markets can be modified to allow integration of intermittent RES.

In **Chapter 2**, we develop a tailor-made analytical model in order to evaluate the benefits (for an agent managing the wind power production within a given power system) to participate into the intraday electricity market.

We are then able to determine how technical parameters such as the flexibility of the power system and the evolution of wind forecast errors determine the strategy of the manager of wind generation. In particular we show that the correlation between forecast errors at different gate closures will drive this strategy.

These results deliver insights on the impact of the generation mix on the relevance of a specific market design. In this specific case, low liquidity in the intraday market will be unavoidable for given sets of technical parameters and compelling players to adjust their position in the intraday market will then generate additional costs. Moreover, restricting trading at imposed gates may lead to inefficiencies, additional costs, and lost trading opportunities.

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### ***On exposing RES to market signals: economic curtailment of intermittent RES***

Even if they were perfectly predictable, the variations of generation by intermittent RES would still challenge the operation of power systems. As a rather inflexible consumption must match generation at all times, and as RES benefit of priority of dispatch, variations of the generation by intermittent RES must most often be compensated by opposite variations of thermal units' generation. However, it is costly for thermal generators to cycle up or down, to stop and start-up. When these costs are too high, it is hence possible to reduce overall generation costs by curtailing the production of intermittent RES. This illustrates how RES can come to play an active role in order to help the system to cope at lower costs with the variability they introduce.

Therefore, we focus in **Chapter 3** on the benefits of curtailing generation by intermittent RES. We introduce an analytical model that investigates the trade-off between avoided cycling costs and additional generation costs when curtailing RES.

We first determine the level of RES curtailment maximising the social welfare. We show that an active participation of renewables can indeed reduce generation costs, compared to a situation in which they benefit from priority of dispatch.

We then analyse the impact on each category of stakeholders (intermittent RES, thermal generators, consumers). A first insight is that the impact of intermittent RES curtailment on each stakeholder evolves as the quantity of installed renewables increase, which implies that any curtailment compensation scheme will have to be versatile enough to adapt to changing circumstances. Second, we show that leaving the decision of curtailing RES to generators will lead to a sub-optimal level of curtailment, and that this will especially be the case if RES and thermal generators are integrated within a single company.

These results confirm that active participation of intermittent RES and exposure to the market signals will lead to significant benefits as the share of intermittent RES in the generation mix increases. But it also shows that this participation could lead to market power abuses through capacity withholding. An alternative to decentralised decisions by generators could then be a centralised decision by the system operator.

### **3.2 On the ability of European TSOs to finance the required transmission infrastructures**

A new market design will hence be needed to ensure the well-functioning of the power system at all times. Pricing and remunerating flexibility is not only a matter of security of energy supply, but also a matter of ensuring economic efficiency and lowering costs.

Even for regulated entities like the TSOs, the huge investments that are planned in order to connect renewables to the load centres could prove challenging. Financing needs in the short term conflict with the creation of positive value over the long term. In order to illustrate this challenge, we realise in **Chapter 4** a numerical simulation based on data published by the European TSOs.

We assess the ability of European Transmission System Operators to deliver substantial investments in the transmission grid needed to integrate intermittent RES into the European power systems.

We assess the impact of the required expenditures on the balance-sheet of European TSOs under a set of alternative financing strategies, in a best-case scenario of full cooperation between the European TSOs. We show that there are substantial financeability issues, and

that under current trends in tariffs, only half the investment program could be funded. In order to achieve the full program, transmission tariffs would have to increase very significantly by 2030.

We also show that alternative financing strategies can dampen the impact on tariffs, but that this impact will remain limited.

A direct implication of these results is that the developments of the transmission grid required to connect RES and manage their intermittency will be financially challenging. Exposing intermittent RES to the costs they generate could lead to more transparency and make rises in transmission tariffs more acceptable.

This chapter has been published in *Energy Policy*, Volume 62, 2013, pages 821-829.



# Chapter 1

## MELTING-POTS AND SALAD BOWLS: THE CURRENT DEBATE ON ELECTRICITY MARKET DESIGN FOR INTEGRATION OF INTERMITTENT RES

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*This chapter is joint work with Prof. Jean-Michel Glachant and has been published in Utilities Policy, Volume 27, December 2013, pages 57-64.*

### **1 INTRODUCTION: INTEGRATION OF INTERMITTENT RES AS AN ECONOMIC EFFICIENCY CHALLENGE**

European wholesale electricity markets have not been designed to ensure efficient operation and adequate investment in a power system featuring a large share of intermittent<sup>1</sup> Renewable Energy Sources (RES). RES specificities, such as production variability and low-predictability, zero marginal-cost of generation, and strong site-specificity, result in a set of technical and economic challenges. The share of intermittent RES in most European power systems remains relatively low today and their development is framed both by direct support schemes and indirect support schemes such as partial isolation from the market rules (See Batlle, C., I. J. Pérez-Arriaga and P. Zambrano-

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<sup>1</sup> The term “variable” is sometimes considered to describe more accurately the nature of RES behaviour. However, the term “intermittent” is commonly employed and will be used in this paper, referring mainly to wind power and solar power technologies.

Barragán (2012) for a review of existing support schemes). However this development is already significant in countries like Denmark (28% of electricity generated from wind in 2011 according to the Danish Energy Agency), Spain, Portugal, and Germany. Such a large-scale development cannot take place in isolation from the market without creating significant challenges for market operations and system operations.

Intermittency is not a feature specific to RES, and is not featured by all renewables. Variability and low-predictability have always been features of power systems, either as a result of demand variation, or due to unexpected power plants outages. Yet, large-scale development of intermittent RES will introduce further variability in power systems. Day-ahead forecasts of generation by a single wind-farm feature up to 20% errors. Load errors are typically smaller and their evolution easier to predict (Maupas, F. 2008). There will therefore be a higher need for system flexibility.<sup>2</sup> Moreover, these higher needs will have to be provided by a smaller number of operating dispatchable units.

There is a wide range of studies concluding that resources flexible enough to ensure smooth operation of power systems exist. A thorough literature review as well as semi-interviews of experts in the United States have been realised by Sovacool, B. K. (2009). The main conclusion was that there were no technical barriers, but that the main obstacles to large-scale integration of intermittent RES were related to political and practical inertia of the traditional electricity generation system. Some of the technical studies mentioned by Sovacool, such as the one by Gross, R. (2006) do not see any threats to grid stability or the system reliability for large penetration rates (up to 20% electricity generated from intermittent RES). In addition, RES can also provide the required technical flexibility if they receive adequate incentives. In countries with a high share of intermittent RES like Germany or Spain, there are already requirements for fault-ride through capacity, provision of reactive power, frequency and voltage control, and incentives to minimise deviations. The provision of these services is already mandatory in Germany for new power plants, while it is driven by financial incentives in Spain.

The main challenge is thus not a technical but rather an economic one. It is not to find technical solutions, but rather to ensure that stakeholders have the right incentives to develop these technical solutions. As mentioned by Schmalensee, R. (2011), sources of flexibility in operations such as ramping ability need to be more explicitly rewarded.

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<sup>2</sup> A review of the technical challenges and the corresponding needs are further discussed in the context of the MIT Energy Initiative (2012).

The short-run impact of RES development on prices in European electricity markets is mainly due to the quick transition from an existing set of power plants to a new power system featuring significant excess capacity. This leads to a decrease of old and existing power plants load-factor as described in Sáenz de Miera, G., P. del Río González and I. Vizcaíno (2008) and already observed in Spain for instance (Eurelectric 2011). There are also temporary indirect impacts on prices such as the activation of inflexible take-or-pay gas contracts,<sup>3</sup> as described by Pérez-Arriaga, I. J. and C. Batlle (2012). In this article we follow the approach developed by Cramton, P. and A. Ockenfels (2012). The strong development of intermittent RES isolated from wholesale market prices will lead to excess capacity, causing stranded costs. However, compensating existing units is a distributional issue, not an economic efficiency one. The question is then how to ensure an efficient and effective operation and investment in these resources, while achieving the decarbonisation targets at the same time.

It is possible to identify two paradigms for integration of intermittent RES. A first solution ('melting-pot') consists in designing an electricity market that could accommodate RES by exposing them to exactly the same rules as dispatchable generators, and remunerating them the same way. However, one can alternatively argue that there are fundamental differences between RES and dispatchable generators and that they should not be treated the same way. A second solution ('salad bowl') would then be to design a market where intermittent RES and dispatchable generators would be coordinated without being exposed to the same rules and with distinct remuneration schemes.

Under both paradigms, an evolution of the electricity market design will be required. The historical choices made when designing the electricity markets were based on supply by large power plants with rather stable and predictable production, following a fluctuating load. Therefore, a change in the physical nature of the power system will necessarily require an evolution of the range of products traded in electricity markets. More fundamental revolutions in the way electricity markets are conceived might also be needed. These evolutions, and potentially revolutions, will be driven by the changes in two dimensions of power systems operations: time-dimension and space-dimension.

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<sup>3</sup> When gas-fired units are exposed to penalties in case they consume less gas than planned initially, the opportunity cost of consuming this gas to generate electricity is reduced, and a lower consumption leads to lower electricity prices.

A first set of changes will be required to ensure the flexibility needed to manage the variability and low-predictability of RES generation. As generation gets more variable, time-units and space-units of electricity products will need to get finer. Moreover, a wider set of reserve products meeting the different flexibility needs will be required. The balancing markets will hence have a more important role to play and their joint operation with forward markets like the day-ahead market will become a key source of efficiency. Finally, it is sometimes argued that energy-only markets might not be sufficient to ensure that flexible back-up units recover their costs and that capacity remuneration mechanisms (CRMs) could be needed.

This article aims to review the different arguments that have been developed recently in key articles dealing with the integration of renewables into power systems and electricity markets. We structure these arguments into relevant blocks of analyses for RES integration. In section 2, we identify two paradigms allowing RES-integration: melting-pot and salad-bowl integration. We use these two paradigms as a frame to analyse the main insights developed in previous works by pioneering authors. In section 3, we focus on the new definitions required to ensure that the value of flexibility will be reflected. It implies the need for finer locational and temporal definitions, as well as less-restrictive price boundaries, both all across the sequence of electricity markets. Finally, the rationale for CRMs is exposed and challenged in section 4. The policy implications of this overview can be found in section 5.

## **2 THE TWO PARADIGMS OF RES INTEGRATION**

In liberalised European electricity markets, coordination between participants is driven by price-signals. Yet, under current arrangements, intermittent RES are usually kept out of the market and receive most of their revenues from support schemes. As a result they are isolated from signals driving dispatchable production, and must be treated as inflexible “negative demand”. It is very likely that the signals necessary to ensure efficient operation and investment, of RES capacity but also of flexible generation resources, would then be distorted by a significant development of intermittent RES. In this section, we introduce the two paradigms that build on the literature discussing the challenge of RES integration. In the ‘melting-pot’ paradigm described in section 2.1, intermittent RES and dispatchable generation are integrated under uniform market arrangements. In the ‘salad bowl’ paradigm described in section 2.2, rules are adapted to the specificities of each set of technologies.

## 2.1 Convergence towards a melting-pot integration

The difficulties currently faced by conventional generators to recover their costs are mostly due to the massive introduction of excess generation capacity in an existing power system. What can be observed today is the impact of an unexpected shock on a set of previously existing long-lived assets. The interaction between short-run direct effects and the longer-run indirect effects after adaptation of the generation park is for instance described in analytical studies by Sáenz de Miera, G., P. del Río González and I. Vizcaíno (2008), and Keppler, J. H. and M. Cometto (2013). On the short-run, reduced electricity prices and residual load (defined as load minus generation by intermittent RES) predominantly affect technologies with high variable costs such as gas turbines. On the long-run, the evolution of the residual load impacts mostly technologies with high fixed costs such as nuclear power plants.

This might be only a transition phase: once competitiveness of RES will have been achieved, RES could be considered as active units exposed to the same rules as conventional generators. It is the position of the European association of the electric industry (Eurelectric 2010) to assert that the market will then find a new equilibrium position and the associated prices able to stimulate the needed investments. In particular, Eurelectric argues that wind generators should be subject to the same scheduling and balancing obligations as conventional power plants. Similarly, for Pérez-Arriaga, I. J. (2012) the share of wind power is reaching such levels that they cannot be considered as neutral passive units: renewables must operate as other power plants and participate in maintaining power systems stability.

A thorough review of the positive effects of ‘melting-pot’ integration is developed in an analysis of interactions between support schemes and market design realised by Hiroux, C. and M. Saguan (2010). These benefits include optimal selection of generation sites, improvement of maintenance planning and technology combinations, control of production in extreme cases and higher efficiency of system balancing in general, incentives for innovation, better production forecasts and transparency. As a result, the authors of this study recommended to increase the exposure of intermittent RES to price-signals by adapting support schemes, and to eliminate distorted market signals. Hiroux and Saguan however acknowledged that it might lead to higher risk and higher transaction costs that should be taken into account.

Note that full market integration doesn't mean that intermittent RES should not receive additional revenues. There might be additional positive externalities justifying such additional remunerations.<sup>4</sup>

## 2.2 Fundamental differences and salad bowl integration

### *The rationale for salad-bowl integration*

Even if the costs of generating electricity using intermittent RES get low enough to compete with dispatchable thermal generators, there will still be fundamental differences between non-dispatchable and dispatchable units. On the one hand, intermittent RES have very little incentives not to generate when it is possible, as their marginal cost is zero. A major exception is at times when electricity prices get negative and become low enough to offset any premium received by the RES generator. On the other hand, there is little intermittent RES can do if the resources they are based on are not available. Complementary resources (dispatchable generation units, storage units, or demand reduction) must then provide back-up for RES generation.

This has led several experts to claim that RES integration should address structural discrepancies between intermittent RES and dispatchable generation and not consider that the issue of RES integration is a transitory one. RES integration should hence follow a 'salad bowl' approach, taking into account the specificities of each resource and applying different rules to fundamentally different power units. Four kinds of arguments can be found in the literature: incompatibility between dispatchable units with low variable-costs and energy markets based on marginal pricing, inadequacy of uniform retail pricing to ensure optimal allocation, inability of RES to react to price signals, and limitation of market power.

First of all, as put by Finon, D. and F. Roques (2013), investment in RES, even commercially mature, might not be financially viable if current remuneration mechanisms are removed. They argue that this is a structural fact due to low variable costs leading to lower prices, lower annual load factor, and disappearance of scarcity rents resulting from the high correlation between peak demand and wind power contribution. In addition, this would not only impact the development and revenues of RES but also undermine the case for investments in semi-load technologies. By opposition to the assumptions made by Eurelectric, Finon and Roques conclude that the current market arrangements would not

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<sup>4</sup> See for instance Borenstein (2011) for a complete discussion of arguments for subsidising RES.

lead to a new equilibrium, in which adequate prices could stimulate the needed investment. However, a solid demonstration of this argument, that contradicts more fundamental economic analyses, is missing.

A second argument, building on a rigorous economic analysis is provided by Chao, H.-p. (2011) and Ambec, S. and C. Crampes (2012). Both developed analytical modelling and demonstrated that ex-ante uniform retail pricing does not allow decentralising the energy mix. In the absence of dynamic pricing, in which prices are contingent to the availability of the intermittent source, either cross-subsidies or structural integration within a single company would be required to ensure optimal allocation. Note that if dynamic pricing were to be implemented, a competitive energy-only market would allow market mechanisms to implement the optimal generation mix, while delivering at the same time sufficient revenues to cover the capital costs for the capacity investment. These results seem to contradict the reasoning of Finon, D. and F. Roques (2013): the main obstacle to a long-term functioning of an energy market would not be the characteristics of intermittent RES but the lack of dynamic pricing.

Some authors employ a third kind of argument and justify salad bowl integration by a reduction of risks and transaction costs, rather than by a fundamental market failure. As pointed out by Klessmann, C., C. Nabe and K. Burges (2008), exposing RES to market signals to which they are not able to react will hinder RES development without bringing any benefits. As wind power producers have high incentives to generate electricity whenever the wind is blowing, it is pointless to expose them to more accurate price-signals. Higher risks will lead to higher capital costs, and more complex schemes will also favour large players. Batlle, C., I. J. Pérez-Arriaga and P. Zambrano-Barragán (2012) also insisted on the fact that there is little efficiency improvement when linking remuneration of RES to wholesale electricity prices, as non-dispatchable generators have no mean to adjust their output. The scope for efficiency gains by planning maintenance at times of low electricity prices will also be quite limited, as availability rates are very high. In their survey about RES integration in Europe, Eclareon (2012) estimated the technical availability factor of wind turbines to 97.5% while it is close to 100% for PV panels.<sup>5</sup>

Finally, Batlle et al. explained that exposing RES-E to market prices would create incentives for incumbents owning both conventional and RES generation to abuse their

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<sup>5</sup> This impressive figure is due to the fact that there are no moving parts in PV; maintenance mostly consists in cleaning the panels.

market power. Therefore, they recommend to distinguish non-dispatchable RES from dispatchable RES, and to expose only the latter to price signals.

### ***Discussion of the main arguments in favour of salad-bowl integration***

The nature and the conclusions of these four main arguments are very different. The first point is that a long-term stable market equilibrium could not be found, as a result of the fundamental differences between intermittent RES and dispatchable units. Any kind of melting-pot integration would then be impossible. However, this assumption is not really justified on economic grounds: from a theoretical point of view, a new equilibrium could be reached, as for instance concretely described in Sáenz de Miera, G., P. del Río González and I. Vizcaíno (2008). Indeed, in the case when, after a transitory phase, intermittent RES become commercially mature (i.e. able to compete with conventional technologies for low load-factors), there will still be a need for back-up flexible units. These resources (for instance generation capacity or demand side management) will be needed at times when intermittent generation is not available to meet load. Prices would then have to be high enough at times of scarcity to cover the fixed costs of these flexible resources, and a new equilibrium would be found between low-carbon intermittent resources and peak or semi-load technologies. We agree that some of the features of this optimal generation mix, such as high uncertainty attached to the low number of running hours, negative prices, or need for high scarcity prices will lead to risks for investors in all kinds of generation technology. Yet this is not a structural barrier to the long-term coordination of investments by an energy-only market.

The second point emphasizes the need for dynamic retail pricing as a requirement to melting-pot integration, but does not present melting-pot integration as impossible, once such a pricing would be put into place.

The third argument claims that melting-pot integration could be inefficient as it would increase risks for intermittent RES while the prospect for efficiency incentives would remain limited. This argument makes sense at times when the priority is to develop significantly the share of RES in the generation mix. However, in a system featuring a high share of intermittent RES, these risks are transferred to conventional generators and to consumers, who undergo the price and volume effects. Risks should therefore be allocated back to the entities that are most able to manage them.

At last, there are more proper way to deal with market power abuse than introducing an artificial separation between intermittent resources and dispatchable generators. In

addition, if a large part of the market resources is made to behave in a non-flexible way, it is likely to increase the market power of the remaining dispatchable generators.

From this section, we can therefore conclude that the only major obstacle to melting-pot integration is the absence of dynamic pricing. While salad-bowl integration can reduce risks for intermittent resources and foster their development, this is not efficient in a system featuring a high share of technologically mature intermittent resources. Last but not least, the alleged fundamental inability of energy markets to remunerate generators as the share of intermittent RES increases is yet to be proved.

### 3 EVOLUTION OF PRODUCTS EXCHANGED

Even in case intermittent RES are kept isolated from the electricity markets, the markets will still be impacted by RES.<sup>6</sup> Hence, independently from the paradigm chosen for intermittent RES integration, the issue of market design remains highly relevant.

Exchanges in electricity markets are based on a set of definitions (e.g. temporal and locational definitions). These definitions are based on a trade-off. On the one hand, broader and simpler definitions (e.g. hourly products) enhance liquidity and reduce transaction costs. On the other hand, more accurate definitions (e.g. 5-minute products) allow participants to express better their willingness to pay, as well as their true opportunity cost, for a specific product. In Europe, power markets have traditionally been conceived in accordance with the physical properties of conventional units, and simplifications have been introduced with the aim to enhance competition: energy products are for instance typically defined on an hourly basis<sup>7</sup> (See for instance a review of existing definitions in Barquín, J., L. Rouco and E. Rivero (2011)). As the share of variable sources of energy in the generation mix increases, the impact of these simplifications gets more significant, and these definitions might need to evolve.<sup>8</sup>

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<sup>6</sup> An extreme case is the one in which a large share of RES has full priority of dispatch and receives fixed tariffs. Their production is then considered as inelastic negative demand, but the load factor of thermal units as well as the congestion of transmission lines is still driven by RES production.

<sup>7</sup> 15-minute products have been introduced on the German intraday market in December 2011.

<sup>8</sup> Note that, while this is out of the scope of this article, the need for new definitions could also impact the gas markets, as a result of the significant role played by gas-fired power plants in

### 3.1 Temporal granularity

As the share of RES increases, variability of electricity generation by intermittent RES becomes the main driver of variations of the net load (defined as load minus generation by non-dispatchable RES). Flexible resources need clear signals to deliver energy when they are needed, and shorter time-unit can deliver these incentives.

A finer temporal granularity of prices is important to provide the appropriate price-signals to investors in flexible resources. Hogan, W. W. (2010) therefore argued that temporal granularity should match as close as possible real operations. In the lack of market signals accurate enough, such technologies would be either too expensive to operate or would require regulatory support.

In addition, shorter time-units also contribute to shifting risks from TSOs to Balancing Responsible Parties (Fruent, J. 2011). Indeed, less differentiated pricing leads to a higher role played by the System Operator and to socialisation of the costs incurred.

However, if the temporal granularity were to be reduced, challenges could arise due to the lack of adequate remuneration for start-up costs in present European energy markets (IEA 2012). While such inefficiencies were estimated by Stoft, S. (2002) to be as low as 0.01% of retail electricity costs in conventional electricity markets, these costs might be underestimated when the number of cycling increases (Troy, N. 2011). This might become an issue for shorter time-frames: if the whole start-up costs have to be internalised in a single energy bid, it is clear that the shorter the time-period, the higher the impact will be on electricity prices.<sup>9</sup>

“Block orders” have been put into place in most electricity markets to deal with non-convexities of power-plant production cost and allow participants to express the complementarities between the different production horizons. However computation time and complexity for participants might become an issue in a system featuring a high number

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renewables integration into the network. HENRIOT, A., M. VAZQUEZ, M. HALLACK, and J. M. GLACHANT (2012): “Ldp Academic Roundtable Redesigning Gas and Electricity Markets to Work Together.”

<sup>9</sup> For instance, internalising start-up costs in a 5-minute energy bid would result in a price increase that would be 12 times higher than for a one-hour energy bid.

of smaller time-periods with many different complex bids.<sup>10</sup> Borggrefe and K. Neuhoff (2011) also pointed out that block bids can prove quite efficient as long as it is relatively easy to identify block of hours for which demand will be higher. As the pattern of residual load becomes more complex, block bidding will also prove increasingly challenging.

### 3.2 Locational granularity

Most authors seem to agree on the necessity of more accurate locational signals in a context of a large-scale development of intermittent renewables (Green, R. 2008, Hogan, W. W. 2010, Smeers, Y. 2008).

The first reason is that the best locations for wind farms are often far from load centres. As a result there will be a need for significant transmission investments.<sup>11</sup> Barth, R., C. Weber and D. J. Swider (2008) argue that, as finding a compromise between locations with good resources and locations with low connection costs becomes increasingly relevant, efficient signals should be provided to investors. Green, R. (2008) also claimed that the greater need to avoid high-cost locations is a strong argument in favour of locational pricing.

The second fundamental argument in favour of nodal pricing is the impossibility to clearly define zones that would reflect physical realities at all times. As the generation by intermittent resources keeps evolving, the congestion patterns will evolve constantly, and nodal pricing seems to be the only option able to match reality at all times (Borggrefe and K. Neuhoff 2011). While the shift from zonal pricing to nodal pricing would create winners and losers among the existing network users and might therefore be politically challenging, ways could be found to compensate losers while conserving incentives to respond to locational prices (Green, R. 2008, Newbery, D. and K. Neuhoff 2008).

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<sup>10</sup> In a system featuring 24 one-hour products, the number of possible consecutive block orders within a day is 300, and computation time then remains limited (Meeus et al., 2009). In a system featuring 288 5-minute products, the number of consecutive blocks within a day is a much more significant set of 41616 combinations.

<sup>11</sup> In the Ten-Year Network Development Plan developed by the association of European Electricity TSOs ENTSO-E, 80% of the new projects are needed to solve bottlenecks created by RES ENTSO-E (2012): "Ten Year Network Development Plan."

Note that it is not only an issue of allocating domestic transmission capacity allocation but also of allocating cross-border capacity. Smeers, Y. (2008) for instance argued that the simplifications introduced to couple markets in the Central Western Europe area would backfire with the growth of wind power. Borggrefe and Neuhoff also insisted on the necessity to enhance trade between regions. They identified two potential solutions: integration within a single nodal pricing region, or coordination of nodal pricing in adjacent systems.

In the absence of locational energy pricing, locational transmission tariffs or deep connection charges could be used (Barth, R., C. Weber and D. J. Swider 2008). However, deep connection charges would only deliver locational incentives at times of investment, and might not be adapted in case of fluctuating congestion patterns. Moreover, the calculations of deep connection charges can prove to be quite complicated, and this complexity will increase as the generation geographical patterns gets more fluctuating.

### **3.3 Price boundaries**

Electricity markets typically feature price limits introduced by regulators to protect consumers against overcharging, in a context of low demand-elasticity. As the profile of the load served by dispatchable generators evolves, more differentiated price-signals are needed to remunerate the flexible resources necessary to operate the power system safely.

#### ***Price caps***

As a consequence of an increasing penetration of intermittent renewables, operations by power generation units will become more variable, and some peaking units will be needed to run only a few hours a year. Price-caps should then be high enough to allow these peaking units to recover their fixed costs over these running hours. Note that in theory, price-caps are put into place to compensate for the lack of demand-response and should be set as equal to the value of lost load (VOLL) for consumers. As the VOLL is not affected by renewables, price-caps should in theory remain identical. Yet in practice, the VOLL is difficult to estimate and price caps are very different among power systems with similar consumer preferences: in Spain OMEL has a cap of €180.30/MWh, in Denmark ELSPOT has a cap of €2000/MWh, the German market has a cap of €3000/MWh. A literature survey of estimates for VOLL was conducted by Cramton (2000) who determined that estimates ranged from \$2,000/MWh to \$20,000/MWh.

According to Eurelectric (2010), low price-caps constitute artificial limits to scarcity-price signals, and undermine the long-term investment prospects in new generation. Yet, a brief analysis of the day-ahead prices in Spain and Germany from January to August 2013 reveals that price caps have not been a binding constraint, neither in Spain nor in Germany (See Table 2).

**Price floors**

Negative prices can appear in electricity markets even without intermittent generation, due to non-convexities of power plant generation costs. However, the introduction of a large quantity of intermittent generation capacity with low marginal costs and benefiting from premiums, will naturally lead to a higher occurrence of negative prices.

There is no theoretical rationale for a limit to price-floors, and the floor for day-ahead prices is very different indeed in electricity markets like Spain (No negative prices), Denmark (-200€/MWh as in the rest of the Nordpool area), or Germany (-3000 €/MWh as in the rest of the CWE area).

Day-ahead prices in Spain and Germany from January to August 2013 indicates that the absence of negative prices in the Spanish electricity markets is already probably a binding constraint (See Table 2). In order to reveal the real value of flexibility, such a constraint should be removed. In particular, in a market in which intermittent RES receive a premium X in addition to market price, the floor for prices should be at least lower than -X, so that RES get an incentive to curtail generation at times of extremely low prices.

This issue becomes even more crucial when taking into account cross-border exchanges of electricity. As pointed out by Eurelectric (2010), the lack of common market rules regarding negative prices will lead to distortions when joining offers of energy in zones with different price boundaries.

	SPAIN		GERMANY	
	Minimum hourly price	Maximum hourly price	Minimum hourly price	Maximum hourly price
January 2013	0.00 €/MWh (16 hours)	87.54 €/MWh	-0.10 €/MWh	98.50 €/MWh
February 2013	0.00 €/MWh (32 hours)	90 €/MWh	7.30 €/MWh	99.90 €/MWh
March 2013	0.00 €/MWh (165 hours)	90 €/MWh	-50.00 €/MWh	120.20 €/MWh

April 2013	0.00 €/MWh (211hours)	90 €/MWh	0.00 €/MWh	109.40 €/MWh
May 2013	16.70 €/MWh	72.50 €/MWh	-3.60 €/MWh	73.90 €/MWh
June 2013	0.00 €/MWh (4 hours)	57.25 €/MWh	-100 €/MWh	60.00 €/MWh
July 2013	11.50 €/MWh	68.69 €/MWh	7.00 €/MWh	65.30 €/MWh
August 2013	20.00 €/MWh	62.88 €/MWh	6.00 €/MWh	130.30 €/MWh

Table 2: Minimum and maximum hourly prices in the day-ahead market in Spain and Germany (Source: OMIE monthly market report ; Mayer, J. (2013))

### 3.4 Ensuring inter-temporal consistency between the different markets

#### *The rising importance of balancing markets*

The key-role played by the day-ahead market in electricity markets today does not match the needs of intermittent RES: forecasts of wind power production indeed improve significantly from day-ahead to real-time (von Roon, S. and U. Wagner 2009). Intraday markets that give stakeholders an opportunity to trade after the day-ahead gate-closure, and real-time balancing markets, should therefore gain in importance as the share of intermittent RES increases.

Cramton, P. and A. Ockenfels (2012) accordingly argue that well-designed power reserve markets interlinked with each other through arbitrage can ensure recovery of fixed costs for back-up generation and, more generally speaking, long-term efficient exit and entry decisions. Prices in the reserve markets will get higher than prices in the day-ahead market in case of higher scarcity of flexible power plants compared to power plants requiring a day-ahead notification, therefore delivering the right investment signals (Barth, R., C. Weber and D. J. Swider 2008).

One must yet keep in mind that all the products aiming to deliver energy at given production time are substitutes. The more products defined, the lower the liquidity might get for these products. Liquidity remains for instance quite low in the intraday markets put into place in Europe, which could be explained by their inadequacy to the real needs of stakeholders, and the complexity for these players to realise arbitrage (Weber, C. 2010). This is why the IEA (2012) warned that the definition of too many flexibility products could create issues of market liquidity and market power, and claimed that the number of products defined should remain limited.

Moreover, if reserve markets play a significant role, RES should be able to participate into the full sequence of markets for the different products, as suggested by the IEA (2012). Note that it does not require the mandatory participation of RES into balancing markets, and that it could even prove costly to constrain intermittent RES to manage their production actively (Henriot, A. 2014). Under a paradigm of melting-pot integration, the only requirement would be to expose RES to balancing costs and to give them the possibility of delivering balancing services.

### ***Ensuring consistency between day-ahead and balancing services***

Smeers as well as Borggrefe and Neuhoff (2011) criticize the multiple arrangements governing the organisation of day-ahead, intraday and balancing markets. For Smeers, Y. (2008), a single trading platform should be put into place, with continuous active trading from day-ahead to real-time. Components currently missing include intra-day markets for reserve capacities, and the integration of congestion management with the intra-day markets and ancillary services markets. When transmission capacity is priced in the day-ahead market but is free in the intraday market, distortions are created that shatter the inter-temporal consistency between the different trading spaces. For consistency purpose, the locational granularity should then be the same for the forward markets (e.g. day-ahead) and the balancing markets. A fully functional market for locational reserves would then be needed (Baldick, R., U. Helman, B. F. Hobbs and R. P. O'Neill 2005).

Other distortions can hinder the financial links between the forward markets (i.e. Day-ahead and Intraday markets) and the balancing arrangements. Vandezande, L., L. Meeus, R. Belmans, M. Saguan and J. M. Glachant (2010) described how the existence of asymmetric penalties in some balancing mechanisms would penalise wind producers and generate incentives to under-nominate injections in the forward electricity markets, leading to higher total system costs. Similarly, De Vos, K., S. De Rijcke, J. Driesen and A. Kyriazis (2011) pointed out that putting a cap on imbalance tariffs would “[violate] the link between the reserve market and the imbalance tariff” and thus endanger the well-functioning of balancing markets. As a consequence, the definitions and boundaries mentioned in the previous sections should be applied similarly in the full sequence of markets.

Green, R. (2008) also advocates integration of energy and ancillary services, as it is often the case in the United States. It is then possible to take into account efficiently the different technical constraints and manage the different substitutes in a single optimisation program, without increasing the complexity for participants. Similarly

Borggrefe and K. Neuhoff (2011) favour pool type trading arrangements and joint provision of energy and balancing services. This would solve the lack of consistency resulting from a separation between balancing services that are typically acquired by the TSOs, and energy products in day-ahead and intraday markets, that are exchanged either on power exchange or bilaterally.

## 4 INTRODUCTION OF CAPACITY REMUNERATION MECHANISMS

### 4.1 Impact of intermittent RES on the rationale for Capacity remuneration

The large-scale deployment of out-of-market intermittent RES has raised concerns that dispatchable power plants used as a back-up might not recover their investment costs. According to the European association of the electricity industry Eurelectric (2011), there are two main drivers for an increasing “missing-money” problem: lower load-factor for conventional power plants, associated to increasing uncertainty surrounding potentially lower<sup>12</sup> prices.

Some of the arguments traditionally used to justify the need for a capacity remuneration mechanism (CRM) will indeed gain strength as the penetration of intermittent RES gets more significant. In addition to the lack of demand-response, part of the supply-side will also get less responsive as intermittent RES have incentives to generate as much energy as possible. The need for high scarcity prices will increase, and the limits imposed by price-caps will hence have a higher impact. Finally the policy-driven developments currently taking place will add further uncertainty for producers.

As a result, policymakers might have to consider introducing a CRM to ensure generation adequacy. For Finon, D. and F. Roques (2013), as mentioned in section 2.2, there is not only a transitory need for a CRM, but also a structural one: even when RES become competitive, a market-wide capacity mechanism would be needed to ensure investment in all reliable capacities.

However, Cramton, P. and A. Ockenfels (2012) caution that CRMs should not be designed to compensate the stranded costs of existing producers, at times of transition to a system with a large-share of renewables. Wrong instruments risk to introduce distortions and to reduce market efficiency. Similarly, in their study of the rationale for the introduction of

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<sup>12</sup> As described by Perez-Arriaga & Batlle (2012), the impact on average prices might still be quite modest in some power systems with a rather flat bidding curve.

CRM, the members of Eurelectric remain however quite circumspect: priorities should be to remove distortions such as price-caps, ensure demand participation, and enhance market integration. CRMs would then be introduced only if long-term security of supply were still threatened despite the previous improvements. Furthermore, these CRMs should be designed as a temporary mechanism to be phased-out once the market would be able to deliver the investment incentives needed.

#### **4.2 Consequences on the paradigm for RES integration**

The design of a Capacity Remuneration Mechanism has been the subject of an extensive amount of literature (Batlle, C. and I. J. Pérez-Arriaga 2008, Cramton, P. and A. Ockenfels 2012, Joskow, P. L. 2008), and is not at the core of this article. However, it is interesting to look at the consequences of implementing a CRM on the choice of a paradigm for integration of intermittent resources.

Under the melting-pot paradigm, all resources (including intermittent RES) would be allowed to bid for capacity. Finon and Roques explain that a single tool could then be developed to promote both investments in RES and generation adequacy, e.g. a market-wide capacity forward auctioning. There are however serious obstacles to the participation of intermittent RES into a CRM, as these resources are by nature not available all the time. Estimating their capacity factor, or the value of their contribution to the system reliability, is therefore a complex task (Pérez-Arriaga, I. J. 2012). Moreover, in a system in which the need for back-up would be driven by the availability of intermittent RES, these resources would not be available at times when most needed and would be exposed to severe penalties. In PJM for instance, intermittent RES participation is limited and they only receive less than 1% of the CRM revenues.

The implementation of a CRM will therefore lead to imposing the “salad-bowl” paradigm, by creating a separated market, complementary of the energy markets but accessible only to dispatchable generators.

#### **4.3 Minimum requirements for a CRM**

While there are many reforms considering the introduction of CRMs, some of the designs taken into consideration have little to do with the ability of resources to generate

electricity in a flexible way.<sup>13</sup> The CRM should indeed reflect the need for specific resources with adequate operational capabilities. As put by Gottstein, M. and S. Skillings (2012), it is not only about helping investors to choose whether to invest but also what to build. While generators were previously asked to be available at times of peak demand, they would then be needed at less predictable times of high residual load. They should also be able to cope with more challenging ramping requirements and a range of adequate products might have to be defined. Hence, in order to signal adequately the needs for flexibility, a Capacity Remuneration Mechanism should feature a spatial and temporal granularity that would be similar to the ones of the energy markets described in section 3. It mechanically runs out the possibility of a simple CRM design as an alternative to complex energy markets for energy and ancillary services.

## 5 POLICY IMPLICATIONS

### 5.1 Policy implication 1: “Melting-pot” integration should be implemented.

Integration of intermittent resources refers to two different paradigms. It can be conceived as a “melting-pot” integration, in which active intermittent RES are exposed to the same rules and rewards as dispatchable generators. Alternatively, it can be seen as “salad-bowl” integration: flexible resources are developed to cope with the pressure of a larger share of passive intermittent RES. As summed up in section 2, there is no major obstacle to a melting-pot integration of intermittent RES into electricity markets, once minimum requirements such as dynamic pricing and adequate definitions will have been put into place.

### 5.2 Policy implication 2: As the nature of the generation mix evolves, the definition of products exchanged should evolve.

**Finer locational and temporal granularity will be needed**, as described in section 3. There are concerns that an increase in the number of products exchanged could hinder liquidity of electricity markets. However, if flexibility is to be rewarded through market mechanisms, the value of flexibility (i.e. the ability to generate at a specific time and a specific location) must be reflected in these markets. In particular, nodal pricing appears as the best option to reflect the variability of flows.

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<sup>13</sup> This is for instance particularly blatant in the case of the CRM put into place in the PJM electricity market, where coal-fired power plants with 48-hour notice requirements receive the same reward as fast-responsive plants (Gottstein & Schwartz, 2010).

**Price boundaries should reflect the value of flexibility. In particular negative prices should be implemented.** Intermittent RES typically feature low marginal costs and are therefore reluctant to curtail generation when the resource they use is available. On the other hand, it is not possible for them to generate electricity when the same resource is not available. Prices at times of scarcity and abundance will therefore have a higher role to play and should be set accordingly. Discrepancies between national markets could also be a source of distortions. Price-caps do not seem to be binding in today's markets, but this should be ensured as the generation mix evolves, and if the time-units get shorter. The absence of negative prices in Spain already appears as a limit to the expression of the value of flexibility.

**5.3 Policy implication 3: Balancing markets and reserves will play a key-role in future electricity markets. Joint optimisation of consistent reserve markets and energy markets will be needed to ensure efficiency.**

**Consistency should be ensured across the different electricity markets.** In order to avoid distortions, identical finer product definitions should be implemented over the whole sequence of trading spaces from day-ahead to real-time, but also harmonized between countries.

**Joint optimisation of energy and balancing services will be needed.** Reserve products are substitute to energy products, and balancing services should represent a growing share of the energy exchanged, as a result of low-predictability of intermittent resources. The complexity resulting from the need to clear simultaneously and sequentially the related markets could require "pool type" trading arrangements.

**5.4 Policy implication 4: Capacity remuneration mechanisms are not needed and will only add a layer of complexity to the existing markets.**

First of all, some of the difficulties currently faced by conventional generators are a transitory phenomenon that should disappear once RES will take an active part in the market. There is no theoretical reason why energy markets with adequate price boundaries would not deliver efficient operation and investment signals.

Besides, what matters in a power system featuring a large share of intermittent RES is not capacity, but the ability to deliver electricity when, and where, needed. Any capacity remuneration mechanism should therefore feature the same level of complexity as the energy markets previously described.

Finally, by creating a market that would in practice be closed to intermittent resources, the implementation of a CRM would result in a de facto “salad-bowl” integration. It would therefore constitute a major obstacle to convergence towards a simple market equilibrium.



# Chapter 2

## MARKET DESIGN WITH CENTRALISED WIND POWER MANAGEMENT: HANDLING LOW-PREDICTABILITY IN INTRADAY MARKETS

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### 1 INTRODUCTION

The integration of a significant share of variable renewables in the electricity generation mix is a source of economic and technical challenges. Wind generation variability and low-predictability constitute a major obstacle to the integration of wind farms into electricity markets.<sup>1</sup>

We study in this article the case when intermittent RES are not isolated from electricity markets and considered as a standard generator and we focus on one of the possible solutions to manage the low predictability of electricity generation by wind farms: the use of Intraday Markets (IM). Wind forecasts improve significantly when realised closer to generation. Giving generators a chance to adjust in the IM their commitments realised in the Day-Ahead markets could help renewables to lower their imbalance costs.

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<sup>1</sup> For more details, the reader can for instance refer to the recent study by MIT: PÉREZ-ARRIAGA, I. J. (2012): "Managing Large Scale Penetration of Intermittent Renewables," MIT.

Intraday markets give players an opportunity to trade and to modify their production schedules after the day-ahead gate-closure. They are already in place in most European countries but their design is subject to significant variations. They can in particular be continuous (Germany, Denmark, France) or feature discrete auctions (Spain, Italy). Despite wind already representing a significant share of generated electricity in several countries, liquidity in IM remains low and the share of electricity traded in IM is quite incidental.<sup>2</sup> Complementary rules have sometimes been put into place to increase liquidity. For instance, from January 1, 2010, TSOs are required in Germany to balance any difference between volumes of power from renewable sources sold in the Day-Ahead auction and the feed-in based on the intraday forecast (Besnier, D. 2009). While such a regulatory measure will lead to a higher liquidity in the IM, we argue it could also lead to additional costs. The purpose of this article is to study under what conditions it will be beneficial for wind generators to trade in IM to manage wind low-predictability.

We build a simple analytical model to study how the prediction error for electricity generated by wind farms for a given generation time can be managed in IM. In order to focus on the effects of low-predictability for a single hour, we do not consider interdependency between adjacent generation times. We suppose wind generators are aggregated into a single player who commits to generate a given quantity in Day-Ahead markets. Due to forecast errors, this player is exposed to imbalance costs when the actual output is different from its financial position. This player is also given the possibility to adjust its commitments by interacting with thermal generators<sup>3</sup> at a set of gates within the IM. We also introduce a parameter to take into account the system flexibility in our model. Due to the limited technical flexibility of thermal generators, it is more expensive to procure energy on short-notice.<sup>4</sup>

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<sup>2</sup> In 2009, the volume traded within the organised IM in Germany was 4.2% of the volume traded in the organised Day-Ahead market. For the same year in Spain, the volume traded in the MIBEL IM was under 16% of the total volume traded within the organised markets. (Source: Barquin et al. 2011)

<sup>3</sup> In this article, the term “thermal generators” is used to refer to all units considered as having a predictable output. Thus large hydropower can also be included in this abusive simplification.

<sup>4</sup> According to a recent study by the MIT Energy Initiative (2012), nuclear plants (featuring low marginal costs) require six to eight hours to ramp up to full load, while coal plants can ramp their output at 1.5%-3% per minute. The most flexible coal units are the smaller and older plants with less efficiency.

We use this model to study the average profits of a wind power producer using the best predictions available to adjust its position in selected gates from IM and compare it to the average profits realised by a producer adopting a more passive attitude. It is less expensive to manage imbalances earlier, but there is a risk of correcting self-compensating deviations. This process allows us to establish a set of critical values for the technical properties of the forecast error. Relevant parameters include standard error, correlation between errors at different times, and additional costs of purchasing electricity closer to real-time. Our results indicate that the value of these parameters will determine whether it is a good strategy for the producer to use updated predictions to trade in the intraday market at a given time. As these parameters evolve with each gate-closure time, setting discrete auctions at a sub-optimal time will deter participants from trading within this time period.

## 2 PREVIOUS WORKS

Despite the relatively low volume of electricity currently traded in intraday markets, their alleged potential to assist the integration of intermittent renewables such as wind led to the development of a range of studies focusing on this topic. For example, Borggreffe and K. Neuhoff (2011) and Hiroux, C. and M. Saguean (2010) both mentioned the use of IM to manage wind low-predictability. Borggreffe and Neuhoff (2011) presented intraday markets as a tool to keep the volume of balancing services low in systems featuring a significant penetration of intermittent renewables but did not consider oscillating predictions.<sup>5</sup> Hiroux and Saguean (2010) argued setting the gate closure that closes intraday markets near real-time would help to reduce wind integration balancing costs.

A first category of studies focusing on the IM consists of empirical analysis of players' participation in IM, such as Weber, C. (2010) and Furió, D., J. J. Lucia and V. Meneu (2009). Weber (2010) focused on the volume exchanged in several European Intraday Markets. He estimated a theoretical potential for position adjustments of wind generators in intraday markets and deduced that the amount of exchanges reached in these markets were quite low when compared to this potential. Weber (2010) distinguished two possible explanations for poor liquidity. A first reason could be poor *market design*. In this case, it can moreover become a self-sustaining phenomenon, as the absence of liquidity reduces

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<sup>5</sup> The term "oscillating predictions" refers to the case when the successive updated forecasts for the same generation time are alternatively increasing and decreasing when getting closer to real-time.

the trust of participants into IM. Another possible explanation can be the absence of a real need for IM, i.e. a question of *market structure*.<sup>6</sup> There is a fundamental difference between these two drivers with consequences regarding policies to adopt. Yet no clear conclusion was reached regarding the exact source of low liquidity. Furió et al. (2009) realised a statistical analysis of trades made in the Spanish Intraday markets. This study revealed that about two thirds of the exchanges realised within each of the six trading sessions were linked to the hourly horizons negotiated for the last time in this session. Most of the time only one gate out of six was really used by participants. They furthermore added the low liquidity calculated could be due to an absence of need to make adjustments in the IM.

A second category of studies features models to estimate the value for wind power generators of trading into intraday markets. Usaola, J. and J. Angarita (2007) considered three possible strategies in IM: no bidding, bidding best prediction, and an “optimal” strategic bidding. The frame was the Spanish IM, prices were inputs based on historical data, and only one intermediate step was considered in the IM. Results indicated bidding the best prediction was not the optimal strategy and that it was sometimes even preferable not to play at all in IM. Similar results were obtained by De Vos, K., S. De Rijcke, J. Driesen and A. Kyriazis (2011) in the Belgian context. Day-Ahead (DA) and Balancing Mechanism (BM) prices were inputs taken from the Belgium Power Exchange BELPEX while IM prices were estimated through linear interpolation between DA and BM prices. Increasing total balancing costs resulting from trading into IM were explained by oscillating predictions. Maupas, F. (2008) employed a quite sophisticated approach using a power system simulation and modelling the interaction between intraday and balancing markets. He established that it was not beneficial to trade into IM with poor liquidity due to interactions between the different hourly provision horizons. In Maupas’ model, poor liquidity was an exogenous input taken into consideration by setting intraday market prices closer to the BM prices than to the DA prices.

While wind and intraday markets have hence been subject to different approaches, we believe there is room for further investigation. While there seems to be a general intuition in the studies mentioned in this section that trading in IM could result in higher costs in

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<sup>6</sup> Stoft (2002) for instance employed “market structure” by opposition to “market architecture” to refer to properties of the market closely tied to technology and ownership. We will stick to this definition in this article.

case of poor liquidity and oscillating predictions, the calculations made so far did not establish for what kind of forecast precision and for what market flexibility it was the case. By using a simpler analytical model, we might not be able to deliver accurate numerical results but we will be able to focus on the role played by two key technical components: forecast accuracy and system flexibility.

## 3 MODEL

### 3.1 Modelling framework

In our analytical model, wind generators are aggregated into a single player. This player could represent a utility operating the totality of wind power plants, a national aggregator, or a TSO responsible for managing wind intermittency as it is the case in Germany. Our results can be applied to any system featuring one of these structures.

Our player generates energy using installed wind capacity  $W$  and is also able to procure energy from thermal generators in electricity markets. At the gate-closure time of the day-ahead market, this player plans to generate a given quantity of wind energy for a final production horizon. However due to imperfect forecast, the final output will be different from the player position. This “wind player” will therefore need to manage imbalances.

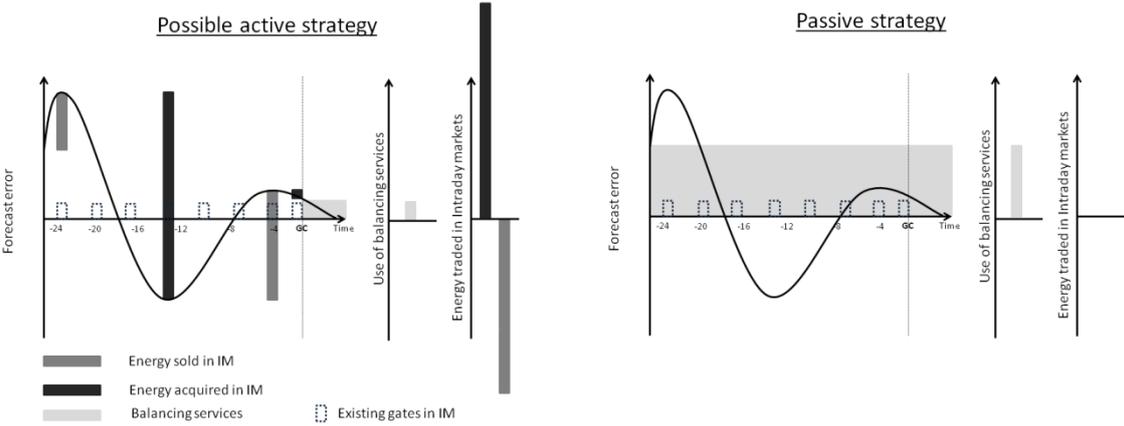
We compare different strategies in our model ranging from a *completely passive strategy* to an *extremely active strategy*. A *completely passive strategy* is to “do nothing” and pay the balancing costs when the final production is realised: this is the case when it is not possible to trade into IM or when the player is not taking part into these markets. An *extremely active strategy* is to use the updated forecast available at each gate of the IM: the wind player will then be interacting with the thermal generators to adjust its positions.<sup>7</sup> As a result, the active player will need to buy or sell less energy in balancing markets (only the remaining error at the last intraday market gate closure) but might buy and sell more energy in the intraday markets due to oscillating predictions. The completely passive strategy and the extremely active strategy constitute the two extreme possibilities of a much more complex set of strategies: in practice, in our model, at each available gate

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<sup>7</sup> If the updated forecast indicates a higher output than the previous forecast the wind player can sell more energy. If the updated wind forecast indicates a lower output the wind player must buy energy.

of the IM, the player can choose whether to adjust its position using the best available forecast. This is illustrated in Figure 6.

We assume that the evolution of the system imbalance is driven by the wind manager generation imbalances, which is a reasonable assumption in a system featuring a significant share of variable renewables managed by a single player.<sup>8</sup> Indeed while load is also uncertain the errors will then be smaller and their evolution is easier to anticipate (Maupas, F. 2008).



**Figure 6: Illustration of two possible strategies: the player chooses to participate in IM at gates H-24, H-12, H-4 and H-2 (left side) vs. the player decides not to participate at all in IM (right side).**

Thermal generators have a limited flexibility. The least flexible plants will not be able to adapt their production to the demand when getting closer to the production horizon or will only be able to adapt it in a restricted way respecting ramping constraints. They will therefore withdraw part of their offers from the supply function, as illustrated in Figure 7. The resulting inverse supply function will therefore feature a steeper slope, and prices will get more expensive when getting closer to the production horizon.<sup>9</sup> Moreover, the units

<sup>8</sup> The assumption that a single player is managing the whole wind power generation is therefore a key assumption in our discussion. Our results would however remain qualitatively true with a significantly dominant player or for any player whose imbalances are strongly positively correlated to the total system imbalances.

<sup>9</sup> Exercise of market power could strengthen the impact of this phenomenon, as illustrated by Green and Vasilakos (2010): when the residual demand for power production by flexible units is high, these units exercise market power to a greater extent and prices rise.

most likely to provide the required flexibility to manage wind variability are usually the ones with high marginal costs<sup>10</sup> (see IEA (2012)).

At last, energy procured in real-time is not always charged at cost-reflective prices (Vandezande, L., L. Meeus, R. Belmans, M. Saguan and J. M. Glachant 2010). Penalties can be imposed by the system operator to provide ex-ante balancing incentives to participants. Such penalties could be included in our model by higher prices for energy procured and lower revenues from selling energy in real-time markets. Due to these extra-costs, participants should then have higher incentives to participate in intraday markets.

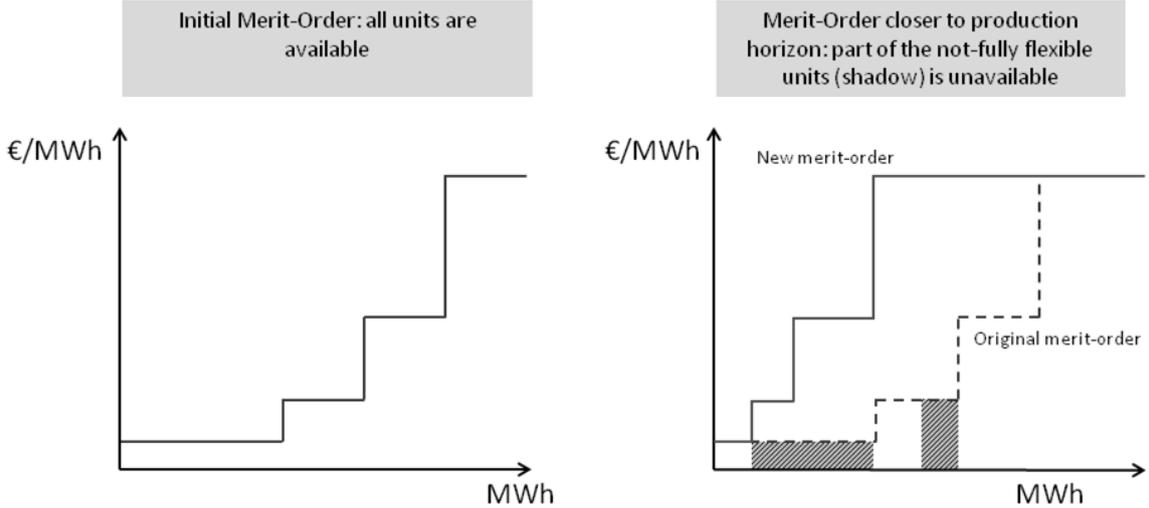


Figure 7: Evolution of the economic merit-order due to limited flexibility

3.2 Model implementation

*Wind player behaviour*

At time  $t_0$ , the wind player plans to generate a wind energy quantity  $w_0$  at time  $t_n$  using the best available forecast.

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<sup>10</sup> It could be argued some very flexible power units, typically hydropower units, also feature low marginal costs. However these generators, as they are the most flexible, can choose to sell their production at any time-horizon. It is likely they will sell their production in earlier markets if prices are higher in these higher markets.

The wind player is then given the possibility to adjust its position at a set of gates determined by market rules. Among the eligible gates, the player will choose to participate (adopt an active strategy) in  $n-1$  gates at times  $t_i$ , where  $i \in \llbracket 1, n-1 \rrbracket$ . This player is therefore taking part in  $n+1$  gates at times  $t_i$ , where  $i \in \llbracket 0, n \rrbracket$ :  $t_0$  is the day-ahead market gate closure time,  $t_n$  is the production horizon when electricity must be generated. For instance, in figure 2 the player decides to participate in IM at gates H-24, H-12, H-4 and H-2 and the  $t_i$  are then  $t_1 = \text{H-24}$ ,  $t_2 = \text{H-12}$ ,  $t_3 = \text{H-4}$ ,  $t_4 = \text{H-2}$  and  $t_5 = \text{H}$ .

At time  $t_i$ , this player will then use the updated production forecast  $w_i$ . The player will cover the quantity  $q_i = w_0 - w_i$  buying energy from thermal generators.  $q_i$  is hereby defined as the net demand at time  $t_i$ . This player following the active strategy at time  $t_i$  and  $t_{i-1}$  will then buy the quantity  $q_i - q_{i-1}$  at time  $t_i$ .

At the final time  $t_n$ , the wind player will cover the net demand  $q_n$  and pay the corresponding imbalance costs. A player having adopted the active strategy in gate  $t_{n-1}$  will be charged the costs corresponding to the remaining energy quantity  $q_n - q_{n-1}$ . By opposition, a player having adopted the passive strategy will be charged the costs corresponding to the energy quantity  $q_n - q_0$ .

The quantities  $w_i, i \in \llbracket 0, n \rrbracket$  are random variables whose behaviour depends on the wind farms characteristics and the wind nature itself. In order to make calculations simpler, we define the variable  $X_i$  representing the wind production forecast error at time  $t_i$  as a share of the realised wind production.

$$X_i = \frac{w_n - w_i}{w_n}$$

The resulting random variable  $X_i$  has an expected value  $E(X_i) = 0$  and a variance  $\sigma_i^2$ . We suppose  $X_i$  and  $w_n$  are independent:

$$\forall i \in \llbracket 0, n \rrbracket, \text{Cov}(X_i, w_n) = 0$$

This simplification is made under the assumption that the forecast error  $X_i$  expressed as a share of the realised wind production is not correlated to the realised wind production  $w_n$ . In other words, there is no systematic relationship between wind power generation and

wind power prediction accuracy.<sup>11</sup> Moreover  $E(X_i) = 0$  indicates there is no systematic underestimation or overestimation at a given time. This is a very reasonable assumption as a forecasting tool presenting such a bias would be adjusted.

### ***Prices formation***

In our model wind power producers interact with thermal generators to buy the extra energy they need or to sell surplus energy. Demand-side is not considered as we suppose the balancing needs driven by the consumption-forecast error will be insignificant in a power system featuring high penetration by intermittent RES.<sup>12</sup> The available thermal generators obey at time  $t_0$  to the following aggregated inverse supply function. For a net demand  $q$ , the corresponding price  $\bar{p}(q)$  is:

$$\bar{p}(q) = a + b \cdot q$$

The price function is therefore linear and parameters  $a$  and  $b$  are inputs that depend on the power system properties. The variable  $b$  will be higher when the range of marginal costs of the different generation units will be higher.

The evolution of costs of dealing with imbalances will play a significant part in the trade-off wind generators are to face. To take flexibility into account in our model we introduce a “penalty function”  $\varphi(t)$ . We assume the value of the penalty function  $\varphi(t)$  increases with time  $t$ : the extra cost of trading later is higher closer to real time.

We suppose a producer who committed at time  $t_{i-1}$  to buy the quantity  $q_{i-1}$  and trading the quantity  $q_i - q_{i-1}$  at time  $t_i$  will pay a price  $p(q_{i-1}, q_i, t_i)$ . The resulting price function obeys to the following equation graphically illustrated in Figure 8:

$$p(q_{i-1}, q_i, t_i) = \bar{p}\left(q_{i-1} + (1 + \varphi(t_i)) \times (q_i - q_{i-1})\right)$$

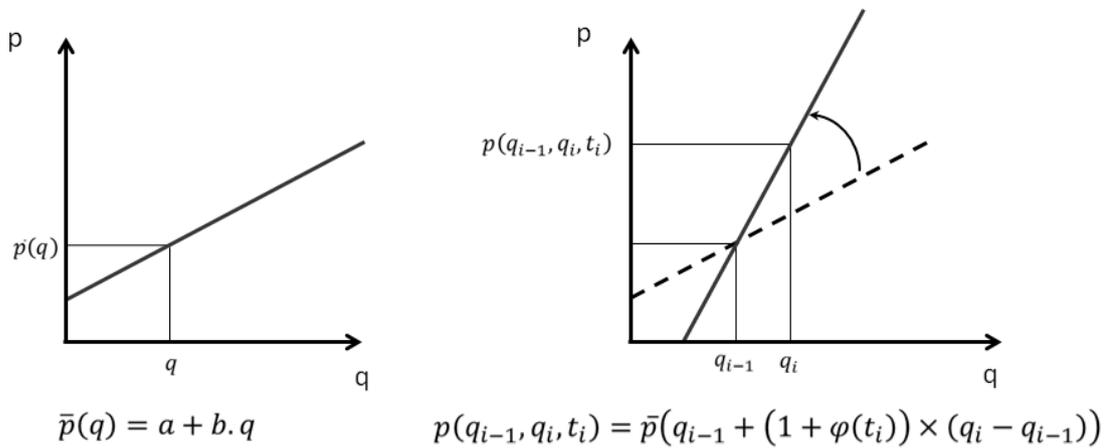
$$p(q_{i-1}, q_i, t_i) = \bar{p}(q_i) + b \times \varphi(t_i) \times (q_i - q_{i-1})$$

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<sup>11</sup> An example of empirical study analysing this property of wind power forecasts can be found in section 6 of Lange (2003).

<sup>12</sup> While outages of thermal units will still be relevant for the network security we considered that due to the low frequency of occurrence they could be neglected in our financial analysis.

In case the system is not perfectly flexible (i.e.  $\exists t \setminus \varphi(t) > 0$ ) the same quantity of electricity bought later by wind generators (when generation by thermal units is higher) will be more costly, while electricity sold later by wind generators (when generation by thermal units is lower) will lead to lower profits.



**Figure 8: Evolution of the inverse supply function in our model**

It is important to point out that representing the classical stepwise merit-order curve by a linear merit-order curve is a quite restrictive assumption. For a given time, in a real electricity market, start-up costs and additional non-convexities might challenge this hypothesis. However the scope of this article is to provide insights of phenomena taking place into IM, focusing on a single production hour. In this context, we considered that neglecting non-convexities constituted a reasonable assumption. The same argument also applies to the approximation by the supply function at different times  $t_i$ .

### ***Picking the best strategy***

A wind power producer having chosen to participate in IM at times  $t_i$  and  $t_{i-1}$  will trade the quantity  $q_i - q_{i-1}$  at time  $t_i$  and pay a price  $p(q_{i-1}, q_i, t_i)$ . The total cost  $C_{IM}$  for a participants being active at times  $t_i$  where  $i \in \llbracket 1, n - 1 \rrbracket$  will therefore be the sum of these transactions<sup>13</sup>:

$$C_{IM}(q_0, \dots, q_n, t_1, \dots, t_n) = \sum_{i=1}^n [p(q_{i-1}, q_i, t_i) \times (q_i - q_{i-1})]$$

---

<sup>13</sup> We consider that transaction costs are not significant and can be neglected in this study.

By opposition a producer staying completely out of the intraday market (what we defined as the passive strategy) will only buy the initial amount of energy at  $t_0$  and pay the imbalance costs corresponding to quantity  $q_n - q_0$  at time  $t_n$ . The total cost  $C_{NI}$  will then be:

$$C_{NI}(q_0, q_n, t_n) = p(q_0, q_n, t_n) \times (q_n - q_0)$$

The player considered will be risk-neutral in our analysis. In order to compare the efficiency of these two strategies, the chosen *active strategy* and the *passive strategy*, we will have a look at the expected value of the difference between these two total costs  $\Delta(t_1, \dots, t_n)$ .

$$\Delta(t_1, \dots, t_n) = \bar{E}(C_{IM}(q_0, \dots, q_n, t_1, \dots, t_n) - C_{NI}(q_0, q_n, t_n))$$

We will then compare the case of a player only active at times  $t_1, \dots, t_j, t_{j+1}, \dots, t_n$  with the case of the player in addition active at time  $t_k$  with  $t_j \leq t_k \leq t_{j+1}$ . We will study the sign of  $\Delta(t_1, \dots, t_j, t_k, t_{j+1}, \dots, t_n) - \Delta(t_1, \dots, t_j, t_{j+1}, \dots, t_n)$  to determine whether it is worth or not being active at time  $t_k$  in addition to  $t_1, \dots, t_j, t_{j+1}, \dots, t_n$ .

## 4 ANALYTICAL RESULTS

### 4.1 General case

To express more precisely the value of  $\Delta(t_1, \dots, t_n)$  it is necessary to introduce the correlation coefficient  $r_{j,k}$  between  $X_j$  and  $X_k$  defined as:  $r_{j,k} = \frac{Cov(X_j, X_k)}{\sigma_j \sigma_k}$

It is then possible to show the following result (see Appendix for demonstration):

$$\Delta(t_1, \dots, t_n) = b \times E(w_n^2) \times \left[ \sum_{i=1}^n A_i + \sum_{i=1}^n B_i - C \right]$$

$$A_i = \sigma_i^2 - r_{i-1,i} \sigma_i \sigma_{i-1}$$

$$B_i = \varphi(t_i) \times (\sigma_i^2 + \sigma_{i-1}^2 - 2r_{i-1,i} \sigma_{i-1} \sigma_i)$$

$$C = \sigma_0^2 \times \varphi(t_n)$$

This result can deliver a few insights. First of all, the costs of picking the wrong strategy (whether it is to play or not at a given time in intraday markets) will be proportional to both the slope of the supply curve  $b$  and the expected value of the square of wind power production  $E(w_n^2)$ . It is important to point out that  $E(w_n^2)$  is higher when the average production is higher but also when the variability of the production is higher.<sup>14</sup> In a system where wind production is steadier, for example because the wind is itself more steady or because wind farms are more dispersed, the errors will also be less important. In a system where the marginal costs of thermal plants, flexible or not, are roughly the same, it will matter less which ones are called to generate.

Finally, the relevance of trading into these gates will be the result of a trade-off between the different members of this equation. The  $B_i$  terms are always positive and represent the “flexibility penalty” of buying energy later in intraday markets when the generator adopts the active strategy. The term  $-C$  is always negative and represents the same penalty paid in case the wind generator adopts a passive strategy. The value of the  $A_i$  term depends on the system characteristics and can be either positive or negative. If correlation  $r_{i-1,i}$  between  $X_{i-1}$  and  $X_i$  is poor then losses resulting from oscillating predictions will be high and it might not be worth trading in intraday markets.

#### 4.2 Results in a simple case with one gate closure in the intraday market

In a recent study of the Spanish electricity market, Furió, D., J. J. Lucia and V. Meneu (2009) estimated that about two thirds of exchanges realised in the IM take place during the last possible platform. It means players use only one gate of the IM for a given hour. It is therefore interesting, in addition to being a good educational example, to study the case when the player is deciding whether to adjust its position (or not) at a single gate between the day-ahead electricity market and the generation time.

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<sup>14</sup> Indeed  $E(w_n^2) = (E(w_n))^2 + Var(w_n)$

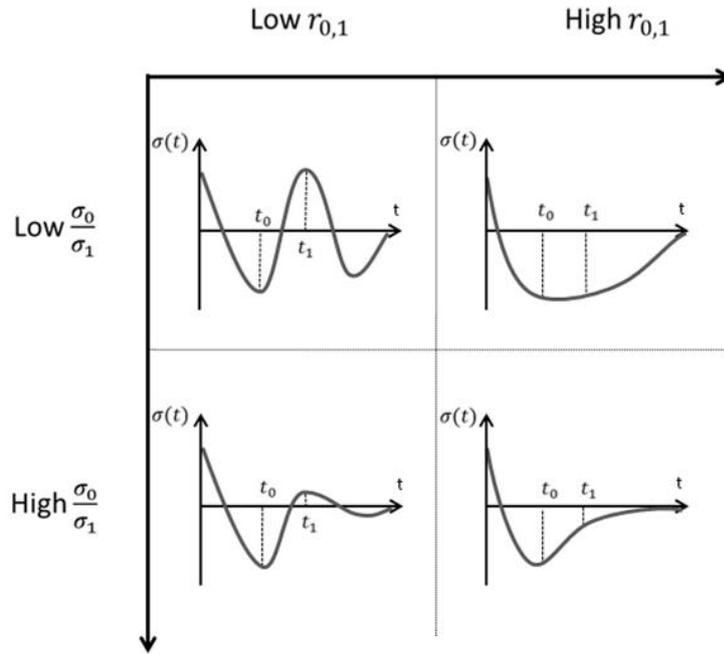


Figure 9: Examples of typical forecasts for given sets of parameters

Our approach consists in identifying for a given flexibility which forecasting abilities will lead to an active use of the additional gate. We introduce the ratio  $\theta_{j,k}$ :

$$\forall j < k \in \llbracket 0, n-1 \rrbracket^2, \theta_{j,k} = \frac{\sigma_j}{\sigma_k} \times r_{j,k}$$

$\theta_{j,k}$  is made of two components:  $\frac{\sigma_j}{\sigma_k}$  indicates how much information is gained between  $t_j$  and  $t_k$  while  $r_{j,k}$  is a measure of the correlation between these two pieces of information. An illustration with two steps is provided in Figure 9.

In our simple case when  $n = 2$  we are able to identify two cases.

**Lemma 1.1** (see demonstration in annex):

$$n = 2$$

For a player being given the possibility to trade at time  $t_1$ :

$\theta_{0,1} \geq 1 \Rightarrow \forall \varphi_{(t_1)}, \forall \varphi_{(t_2)}, \Delta(t_1, t_2) \leq 0$ : it will be beneficial to adopt an active strategy at time  $t_1$ .

**Lemma 1.2 (see demonstration in annex):**

$n = 2$

For a player being given the possibility to trade at time  $t_1$ :

$\theta_{0,1} \leq 1 \Rightarrow \exists \bar{\varphi} / \varphi_{(t_2)} \leq \bar{\varphi} \Rightarrow \forall \varphi_{(t_1)}, \Delta(t_1, t_2) \geq 0$  : it will not be beneficial to adopt an active approach at *time*  $t_1$ .

It is possible to go beyond these mathematical results and explore their meanings. In case  $\frac{\sigma_0}{\sigma_1}$  is low, there is little interest in trading at  $t_1$  since the forecast is not much more accurate. In case  $r_{0,1}$  is low, there is little interest in trading at  $t_1$  as there are higher risks of spoiling energy due to oscillating prediction errors. That's why  $\theta_{0,1}$  is a key parameter.

From lemma 1.1, it is interesting for the producer to anticipate imbalances at  $t_1$  if the forecast error evolution is good enough.

From Lemma 1.2, if the anticipation is not really helpful, i.e.  $\theta_{0,1}$  is low, then it can be interesting or not to anticipate imbalances. If imbalances are never very expensive it is not worth taking the risk of a wrong anticipation.

#### 4.3 Interest of trading at a given gate closure in the general case

Most intraday markets feature several gates (six in Spain) or allow continuous trading. Therefore we will have a look in this section at a general case when a participant is adjusting its position in  $n - 1$  gates in the IM at times  $t_i$  where  $i \in \llbracket 1, n - 1 \rrbracket$ . We study the effects of being active at one more gate at time  $t_k$  and identify a set of criteria that will favour or discriminate against an active approach at this gate. By extension it is then possible to determine in which case a continuous market will be fully used by participants when  $n$  tends to infinity.

**Lemma 2.1 (see demonstration in annex):**

For a player adopting an active strategy in IM at gate closure times  $t_1, \dots, t_j, t_{j+1}, \dots, t_n$  being given the possibility to trade at time  $t_k$  with  $t_j \leq t_k \leq t_{j+1}$  :

$\begin{cases} \theta_{k,j+1} \geq \theta_{j,j+1} \\ \theta_{j,k} \geq 1 \end{cases} \Rightarrow \Delta(t_1, \dots, t_j, t_k, t_{j+1}, \dots, t_n) \leq \Delta(t_1, \dots, t_j, t_{j+1}, \dots, t_n)$  : it will be beneficial to adopt an active strategy at  $t_k$ .

**Lemma 2.2 (see demonstration in annex):**

For a player adopting an active strategy in IM at gate closure times  $t_1, \dots, t_j, \dots, t_n$  being given the possibility to trade at time  $t_k$  with  $t_j \leq t_k \leq t_{j+1}$  :

$$\begin{cases} \theta_{k,j+1} \leq \theta_{j,j+1} \\ \theta_{j,k} \leq 1 \end{cases}$$

$\Rightarrow \exists \bar{\varphi} / \varphi_{(t_{j+1})} \leq \bar{\varphi} \Rightarrow \forall \varphi_{(t_k)}, \Delta(t_1, \dots, t_j, t_k, t_{j+1}, \dots, t_n) \geq \Delta(t_1, \dots, t_j, t_{j+1}, \dots, t_n)$  : it will not be beneficial to adopt an active approach at  $t = t_k$ .

We can deduce from lemma 2.2 that for a given flexibility of the power system and a specific forecast error evolution the active strategy might be more costly than the passive one. This result is coherent with the results obtained by Maupas, F. (2008), De Vos, K., S. De Rijcke, J. Driesen and A. Kyriazis (2011) and Usaola, J. and J. Angarita (2007).

## 5 RESULTS INTERPRETATION

### 5.1 Liquidity in intraday markets

***Conclusion 1: Low liquidity in intraday markets will be unavoidable for a given set of technical parameters.***

A first insight we can get from our analysis is that poor liquidity in intraday markets may result from a rational behaviour of the participants. Our results indeed indicate that the poor liquidity of intraday markets could be explained by the poor information players have to deal with. Lemma 2.2 shows oscillating predictions can deter the players from trading in the IM provided it is not too expensive to procure energy in the balancing markets. This is an intuition already exposed by some of the authors mentioned in the section 2 of this article, but our results enlighten the key role played by the factor  $\theta_{j,k}$ . When the value of this parameter is low, it means the gain of information when getting closer to real-time is not sufficient to compensate the oscillating nature of wind forecasts. Participants acting rationally will then choose not to adjust their positions between day-ahead markets and real-time. Intraday markets will not be used by participants because they do not meet the needs of the participants.

**Conclusion 2: In some cases, compelling players to trade into intraday markets will generate additional costs.**

As long as conditions remain unsuitable, it will not be possible to increase both efficiency and liquidity by changing rules. Compelling wind power generators to trade in the intraday markets will mechanically lead to a more liquid intraday market, but these obligations can potentially result in higher total balancing costs. Higher volumes should not be the objective of regulators. The volume of exchanges in the intraday markets will spontaneously rise (or decrease) following a higher penetration of renewables or technological changes. A prerequisite is obviously that the intraday markets must be in place in the power system, even if they are not used by most participants. If the forecasting tools become good enough, producers will then apply voluntarily what we defined as the *active strategy*, in order to minimise their costs, as shown in lemma 2.1.

Similarly, setting penalties in real-time markets to incentivise participants to balance ex-ante their positions will lead to a higher participation in intraday markets, as in practice the extra cost  $\varphi_{(t_n)}$  of trading in real-time will increase. However the actual costs of generating electricity will not be transformed by such financial penalties and these additional adjustments will not result in a higher efficiency. Increased participation in intraday markets will then be a form of hedge against imbalances with negative consequences similar to the ones described by Vandezande, L., L. Meeus, R. Belmans, M. Saguan and J. M. Glachant (2010).

## **5.2 Trade-offs between continuous trading and discrete auctions**

As mentioned in the introduction, there are two main options available to design intraday markets: continuous markets and discrete auctions (Barquín, J., L. Rouco and E. Rivero 2011). In a continuous market, bids are matched one by one as soon as they match (i.e. when the bid price is higher than the offer price). The main alternative consists in a set of discrete auctions.

**Conclusion 3: Setting discrete auctions in intraday markets may lead to inefficiencies due to lost trading opportunities.**

By opposition to continuous markets, discrete auctions restrict trading to a set of pre-established times. Yet we know from our analysis that the strategy of a player will differ at different times. Depending on the wind forecast properties, a player might for instance be willing to trade at 10 a.m. but not at 9 a.m. or 11a.m. In a continuous market, players can use the experience they acquired day after day, and they will then be able to optimise their behaviour and trade when it is the most interesting for them. In a discrete market

players will not be given such freedom: if conditions are not suitable (i.e. if the gates are set at times that do not fit this player) players will not trade, as shown by lemma 2.2.

That's why we argue restricting trading at imposed gates (as it is the case in an IM featuring discrete auctions) may lead to inefficiencies, additional costs, and lost trading opportunities. This result shall temper assumptions that discrete auctions will lead to increased trade in IM.<sup>15</sup> Obviously there are other sources of inefficiencies in continuous markets related to their inner fundamental properties: as trades are made on a first-come first-served basis in a continuous market, some trades that would not have taken place in a discrete market might take place, and the resulting prices will be less transparent. However, the decision to put into place continuous or discrete intraday markets should take into account the advantages of continuous markets that we described in addition to these drawbacks.

It could be argued that the gate-closure times could be set in a way to reflect players' preferences, which would only be theoretically possible in the case of a single balancing responsible party. Gates should in this case be set after analysing wind forecast evolutions and should be regularly updated as forecasting technologies and the generation park evolve. Such a painful administrative process could be avoided by putting into place continuous markets. The losses would then offset the potential benefits from more efficient allocation in markets featuring discrete auctions.

## 6 CONCLUSION

In this paper, we assessed the different strategies that could be employed in intraday markets by parties responsible for managing wind forecast error. Participants trading in intraday markets face a trade-off: being exposed to imbalance charges or adjusting positions in the intraday market when some relevant information is still missing. Therefore we developed a simple analytical model allowing us to take into account both the system

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<sup>15</sup> The case for discrete auctions is often illustrated by the relatively high liquidity in the Spanish intraday markets. Yet it is important to take into account the fact that in the Spanish electricity market, portfolio bidding is not allowed. Therefore, as underlined by Pérez Arriaga (2005), a significant share of the volumes exchanged in the intraday markets is due to internal re-allocation by participants of the dispatch resulting from the daily market. It is not the case in most other European electricity markets where portfolio bidding is implemented. Therefore the case of the Spanish IM should be exploited carefully.

flexibility (as the lower the flexibility, the higher imbalance charges) and the nature of the wind forecast evolution (as it determines the information available to participants).

While discussions about optimal gate-closures usually focused on the average forecast error and the system flexibility when getting closer to real-time we demonstrated that correlation between forecast errors at different times should be taken into account. We were able to identify the parameter  $\theta_{j,k}$  reflecting both the oscillating nature of wind forecasts and the level of information gained when getting closer to real-time. We showed this parameter plays a key-role in determining the participants' strategies.

Our analytical results underlined the fact that oscillating predictions could indeed explain the poor liquidity in IMs. In this case, a higher volume of exchanges in the intraday market should not be an objective *per se* as poor liquidity could simply reflect the fact taking part into these intraday markets will lead to higher costs: reducing total balancing costs should remain the main objective of regulated TSOs and regulators when establishing rules.

Our analysis also revealed it was unlikely a set of gates would please all participants. Players responsible for balancing wind low-predictability will achieve cost-optimisation spontaneously if they are given the opportunity to trade when they need it. We argue continuous markets provide participants with a sufficient degree of freedom to express their needs. While the liquidity remains low in continuous markets in place in Europe it should yet become naturally higher with an increasing share of renewables in the generation mix, as incentives to reduce costs should lead participants to optimise their participation in intraday markets. Lost opportunities resulting from setting discrete auctions might offset their benefits.

It must be pointed out that our model has been designed to provide general insights about the behaviour of wind players in intraday markets. As a consequence, rather strong assumptions have been employed, and the results obtained might therefore not be universally valid. Relaxing some of the assumptions described in section 3 should however not impact our results significantly: for instance start-up costs that we neglected tend to increase when getting closer to real-time and could be internalised in the supply function. In this paper, it has also been considered that players are risk-neutral. Risk-averse players might have stronger incentives to participate in IM (thus reducing their exposure to imbalances in real-time markets) but our results should not be qualitatively impacted when relaxing this assumption.

Another key-assumption we made is that wind power production is managed in a centralised way. While this assumption is close to reality in some power systems (such as Germany) it might not reflect the more complex situation in other power systems. This assumption is essential when considering that the system total imbalances are driven by the sign of our player imbalances: however our results will remain qualitatively true for any player whose imbalances are strongly (positively) correlated with the total system imbalances. This will in particular be the case if the main wind power producers own similar generation parks: a similar technology employed, in location with similar properties. A possible extension of our work could be to consider the interactions of several players managing only partly-correlated wind power sources.

## **ACKNOWLEDGEMENTS**

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## APPENDIXES

### A.1 Nomenclature

Table 1: Variables employed

Variable	Meaning
$n$	Number of gates after the day-ahead markets closure
$t_0$	Day-ahead market gate closure time
$t_n$	Production horizon
$t_i, i \in \llbracket 1, n - 1 \rrbracket$	Closure time of the $i^{\text{th}}$ gate of the intraday market
$W$	Total wind installed capacity
$w_i, i \in \llbracket 0, n - 1 \rrbracket$	Forecasted wind output at $t_i$ for the production horizon $t_n$
$w_n$	Realised wind output at the production horizon $t_n$
$q_i, i \in \llbracket 0, n \rrbracket$	Net demand associated to $w_i$
$X_i, i \in \llbracket 0, n - 1 \rrbracket$	Forecast error at time $t_i$ as a share of the realised output
$E(X_i)$	Expected value of $X_i$
$\sigma_i^2, i \in \llbracket 0, n - 1 \rrbracket$	Variance of $X_i$
$r_{j,k}$	Correlation coefficient between $X_j$ and $X_k$
$\theta_{j,k}$	Ratio representing the quality of the forecast evolution (see 4.2)
$a$	Constant parameter of the inversed supply-function at time $t_0$
$b$	Slope of the inversed supply-function at time $t_0$
$\bar{p}(q)$	Price associated to a net demand $q$ when all units are available
$\varphi(t)$	Function representing the extra-cost when trading at time $t$

$p(q_{i-1}, q_i, t_i)$	Price associated to demand $q_i - q_{i-1}$ at time $t_i$
$C_{IM}$	Costs associated to an active strategy in intraday markets
$C_{NI}$	Costs associated to a passive strategy in intraday markets
$\Delta$	Expected value of the difference between $C_{IM}$ and $C_{NI}$

## A.2: Expression of $\Delta_\beta(t_1, \dots, t_n)$

$$\Delta(t_1, \dots, t_n) = E \left( \sum_{i=1}^n [p(q_{i-1}, q_i, t_i) \times (q_i - q_{i-1})] - p(q_0, q_n, t_n) \times (q_n - q_0) \right) \quad (1)$$

By definition,

$$\forall q_{i-1}, q_i, t_i, p(q_{i-1}, q_i, t_i) = \bar{p} \left( q_{i-1} + (1 + \varphi(t_i)) \times (q_i - q_{i-1}) \right) \quad (2)$$

And

$$\forall q, \bar{p}(q) = a + b \cdot q \quad (3)$$

Thus by developing (1) we obtain:

$$\begin{aligned} \Delta(t_1, \dots, t_n) &= b \times E(\sum_{i=1}^n [q_i \times (q_i - q_{i-1})] + \sum_{i=1}^n [\varphi(t_i) \times (q_i - q_{i-1})^2]) \\ &\quad - b \times E(q_n \times (q_n - q_0) + \varphi(t_n) \times (q_n - q_0)^2) \end{aligned} \quad (4)$$

We will then estimate each of the four members of this equation

$$E(q_i \times (q_i - q_{i-1})) = E \left( \left( \frac{q_n}{w_n} + \frac{q_i - q_n}{w_n} \right) \times \left( \frac{q_i - q_n}{w_n} - \frac{q_{i-1} - q_n}{w_n} \right) \times w_n^2 \right)$$

As, by definition,  $q_n = w_0 - w_n$  and  $q_i - q_n = (w_0 - w_i) - (w_0 - w_n) = w_n - w_i$

$$E(q_i \times (q_i - q_{i-1})) = E \left( \left( \frac{w_0 - w_n}{w_n} + \frac{w_n - w_i}{w_n} \right) \times \left( \frac{w_n - w_i}{w_n} - \frac{w_n - w_{i-1}}{w_n} \right) \times w_n^2 \right)$$

Thus following notations defined in 3.2 we obtain:

$$E(q_i \times (q_i - q_{i-1})) = E((X_i - X_0) \times (X_i - X_{i-1}) \times w_n^2)$$

And as by assumption (see section 3.2)  $\forall i \in \llbracket 0, n \rrbracket, Cov(X_i, w_n) = 0$  and  $E(X_i) = 0$

$$E(\mathbf{q}_i \times (\mathbf{q}_i - \mathbf{q}_{i-1})) = E(w_n^2) \times E((X_i - X_0) \times (X_i - X_{i-1}))$$

Following notations defined in 3.2 we obtain  $\forall (j, k) \in \llbracket 0, n \rrbracket^2$ :

$$E(X_j X_k) = Cov(X_j, X_k) + E(X_j) \times E(X_k)$$

And, as  $E(X_j) = 0$  and by definition  $Cov(X_j, X_k) = r_{j,k} \sigma_j \sigma_k$

$$E(X_j X_k) = r_{j,k} \sigma_j \sigma_k$$

$$E(\mathbf{q}_i \times (\mathbf{q}_i - \mathbf{q}_{i-1})) = E(w_n^2) \times (\sigma_i^2 - r_{i-1,i} \sigma_i \sigma_{i-1} - r_{0,i} \sigma_0 \sigma_i + r_{0,i-1} \sigma_0 \sigma_{i-1}) \quad (4.1)$$

And by a similar process:

$$E((\mathbf{q}_i - \mathbf{q}_{i-1})^2) = E(w_n^2) \times (\sigma_i^2 + \sigma_{i-1}^2 - 2 \times r_{i-1,i} \sigma_i \sigma_{i-1}) \quad (4.2)$$

$$E(\mathbf{q}_n \times (\mathbf{q}_n - \mathbf{q}_0)) = E(w_n^2) \times r_{0,0} \sigma_0 \sigma_0 \quad (4.3)$$

$$E((\mathbf{q}_n - \mathbf{q}_0)^2) = E(w_n^2) \times \sigma_0^2 \quad (4.4)$$

Moreover:

$$\sum_{i=1}^n (-r_{0,i} \sigma_0 \sigma_i + r_{0,i-1} \sigma_0 \sigma_{i-1}) - r_{0,0} \sigma_0 \sigma_0 = -r_{0,n} \sigma_0 \sigma_n = 0, \text{ as } \sigma_n = 0$$

We can therefore write (4) as

$$\Delta(t_1, \dots, t_n) = b \times E(w_n^2) \times \left[ \sum_{i=1}^n A_i + \sum_{i=1}^n B_i - C \right] \quad (5)$$

Where:

$$A_i = \sigma_i^2 - r_{i-1,i} \sigma_i \sigma_{i-1}$$

$$B_i = \varphi(t_i) \times (\sigma_i^2 + \sigma_{i-1}^2 - 2r_{i-1,i} \sigma_{i-1} \sigma_i)$$

$$C = \sigma_0^2 \times \varphi(t_n)$$

### A.3: Proof of lemma 1.1:

We apply equation (5) in the special case when  $n = 2$

$$\frac{\Delta(t_1, t_2)}{b \times E(w_n^2)} = \sigma_1^2 - r_{0,1}\sigma_0\sigma_1 + \varphi(t_1) \times (\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1) + \varphi(t_2) \times \sigma_1^2 - \varphi(t_2) \times \sigma_0^2 \quad (6)$$

$$\text{As } |r_{0,1}| \leq 1, \sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1 \geq \sigma_1^2 + \sigma_0^2 - 2\sigma_0\sigma_1 \geq (\sigma_0 - \sigma_1)^2 \geq 0$$

$$\text{Hence } \Delta(t_1, t_2) \leq 0 \Leftrightarrow \varphi_\beta(t_1) \leq \varphi(t_2) \times \frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} - \frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \quad (7)$$

We assume that  $\sigma_0^2 \geq \sigma_1^2$  : the uncertainty increases with the prediction horizon.

If we assume  $\theta_{0,1} \geq 1 \Leftrightarrow \sigma_0 \times r_{0,1} \geq \sigma_1$  we obtain the following results:

$$\frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \leq 0 \quad (7.1)$$

$$\text{And as } \sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1 = \sigma_0^2 - \sigma_1^2 + 2(\sigma_1^2 - r_{0,1}\sigma_0\sigma_1) \leq \sigma_0^2 - \sigma_1^2$$

$$\frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \geq 1 \quad (7.2)$$

We also know that  $\varphi(t_1) \leq \varphi(t_2)$  as the flexibility penalty  $\varphi(t)$  increases with  $t$

$$\Rightarrow \forall \gamma_1 \geq 1, \forall \gamma_2 \leq 0, \varphi(t_1) \leq \gamma_1 \times \varphi(t_2) - \gamma_2 \quad (8)$$

Using (7.1), (7.2) and (8) we can show that the following equation is verified

$$\varphi(t_1) \leq \varphi(t_2) \times \frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} - \frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \quad (9)$$

And according to (7) and (9),  $\Delta(t_1, t_2) \leq 0$

#### A.4: Proof of lemma 1.2:

We assume  $\theta_{0,1} \leq 1 \Leftrightarrow \sigma_0 \times r_{0,1} \leq \sigma_1$

By analogy to the proofs of (7.1) and (7.2), we can show:

$$0 \leq \frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \leq 1 \quad (10.1)$$

$$0 \leq \frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \leq 1 \quad (10.2)$$

And therefore:

$$\exists \bar{\varphi} / \forall \varphi(t_2) \leq \bar{\varphi} \Rightarrow \varphi(t_2) \times \frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} - \frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \leq 0 \quad (11)$$

As by definition  $\varphi(t_1) \geq 0$

$$\exists \bar{\varphi} / \varphi(t_2) \leq \bar{\varphi} \Rightarrow \varphi(t_1) \geq \varphi(t_2) \times \frac{(\sigma_0^2 - \sigma_1^2)}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} - \frac{\sigma_1^2 - r_{0,1}\sigma_0\sigma_1}{\sigma_1^2 + \sigma_0^2 - 2r_{0,1}\sigma_0\sigma_1} \quad (12)$$

Using (7),  $\exists \bar{\varphi} / \varphi(t_2) \leq \bar{\varphi} \Rightarrow \forall \varphi(t_1), \Delta(t_1, t_2) \geq 0$

#### A.5: Proof of lemma 2.1:

A player adopting an active strategy in IM at gate closure times  $t_1, \dots, t_j, t_{j+1}, \dots, t_n$  is being given the possibility to trade at time  $t_k$  with  $t_j \leq t_k \leq t_{j+1}$ .

We make two assumptions.

Assumption 1:  $\theta_{k,j+1} \geq \theta_{j,j+1}$

Assumption 2:  $\theta_{j,k} \geq 1$

By definition it will be beneficial to adopt an active strategy at  $t_k$  if and if only:

$$\Delta(t_1, \dots, t_j, t_k, t_{j+1}, \dots, t_n) \leq \Delta(t_1, \dots, t_j, t_{j+1}, \dots, t_n) \quad (13)$$

Most of the terms are present on each side and by developing and simplifying (13) is equivalent to

$$0 \geq \sigma_k^2 - r_{j,k}\sigma_j\sigma_k - r_{k,j+1}\sigma_k\sigma_{j+1} + r_{j,j+1}\sigma_j\sigma_{j+1} + \varphi(t_k) \times (\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k) + \varphi(t_{j+1}) \times (\sigma_k^2 - \sigma_j^2 - 2r_{k,j+1}\sigma_k\sigma_{j+1} + 2r_{j,j+1}\sigma_j\sigma_{j+1}) \quad (14)$$

Under assumption 1,  $\theta_{k,j+1} \geq \theta_{j,j+1}$  and therefore

$$r_{k,j+1}\sigma_k\sigma_{j+1} \geq r_{j,j+1}\sigma_j\sigma_{j+1} \quad (15.1)$$

In addition we know that we assumed greater uncertainty further away from the production horizon:

$$\sigma_j^2 \geq \sigma_k^2 \quad (15.2)$$

Using (15.1) and (15.2)

$$\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1} \geq 0 \quad (16)$$

And according to (16) it is possible to rewrite (14) as:

$$\varphi(t_{j+1}) \geq \varphi(t_k) \times \frac{\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} + \frac{\sigma_k^2 - r_{j,k}\sigma_j\sigma_k + r_{j,j+1}\sigma_j\sigma_{j+1} - r_{k,j+1}\sigma_k\sigma_{j+1}}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \quad (17)$$

We know have to show that inequality (17) is true to ensure that inequality (13) is true.

Under assumption 2:  $\theta_{j,k} \geq 1$  and  $\sigma_k^2 \leq r_{j,k}\sigma_j\sigma_k$

Under assumption 1:  $\theta_{k,j+1} \geq \theta_{j,j+1}$  and  $\sigma_k^2 r_{j,j+1}\sigma_j\sigma_{j+1} \leq r_{k,j+1}\sigma_k\sigma_{j+1}$

$$\frac{\sigma_k^2 - r_{j,k}\sigma_j\sigma_k + r_{j,j+1}\sigma_j\sigma_{j+1} - r_{k,j+1}\sigma_k\sigma_{j+1}}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \leq 0 \quad (18.1)$$

Besides  $r_{j,j+1}\sigma_j\sigma_{j+1} \leq r_{k,j+1}\sigma_k\sigma_{j+1}$

$$\Rightarrow \frac{\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \leq \frac{\sigma_j^2 - \sigma_k^2 + 2\sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2}$$

$$\Rightarrow \frac{\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \leq 1 + 2 \times \frac{\sigma_k^2 - r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2}$$

$$\text{As } \sigma_k^2 \leq r_{j,k}\sigma_j\sigma_k, \frac{\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \leq 1 \quad (18.2)$$

We also know that by definition  $\varphi(t_{j+1}) \geq \varphi(t_k)$  as the flexibility penalty  $\varphi(t)$  increases with

$t$ . Hence using (18.1) and (18.2):

$$\varphi(t_{j+1}) \geq \varphi(t_k) \times \frac{\sigma_j^2 + \sigma_k^2 - 2r_{j,k}\sigma_j\sigma_k}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} + \frac{\sigma_k^2 - r_{j,k}\sigma_j\sigma_k + r_{j,j+1}\sigma_j\sigma_{j+1} - r_{k,j+1}\sigma_k\sigma_{j+1}}{\sigma_j^2 - \sigma_k^2 + 2r_{k,j+1}\sigma_k\sigma_{j+1} - 2r_{j,j+1}\sigma_j\sigma_{j+1}} \quad (19)$$

And (17) is verified, which is equivalent to  $\Delta(t_1, \dots, t_j, t_k, t_{j+1}, \dots, t_n) \leq \Delta(t_1, \dots, t_j, t_{j+1}, \dots, t_n)$ : it is beneficial to the active strategy.

#### A.6: Proof of lemma 2.2:

Similar to 1.2 using equation (17).

# Chapter 3

## ECONOMIC CURTAILMENT OF INTERMITTENT RENEWABLE ENERGY SOURCES

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### 1 INTRODUCTION

In order to foster the development of renewable energy sources (RES) in Europe, RES benefit from priority of dispatch. Following European directive 2009/28/EC priority should be given to RES as long as the safety of the power system is not threatened. The curtailment of electricity, i.e. the use of less RES generation than potentially available, should therefore be minimised and should occur only when needed to ensure security of supply.

However, such a priority should be questioned at times when intermittent<sup>1</sup> RES constitute a significant share of the generation mix. The variability of RES and the limited flexibility of the conventional thermal units constitute a challenge for the operation of power systems. This inflexibility is reflected for instance through the occurrence of significantly negative prices in Germany ((Mayer, J. 2013), Nicolosi, M. (2010)). Such prices reveal that while the variable-cost of electricity generated by RES is equal to zero, releasing the constraints on RES dispatch could lead to benefits. Economic curtailment of RES should then be considered as an additional tool to the technical curtailment of RES.<sup>2</sup>

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<sup>1</sup> The term “variable” is sometimes considered to describe the nature of RES behaviour more accurately. However, the term “intermittent” is commonly employed and will be used in this paper, referring mainly to wind and solar PV technologies.

<sup>2</sup> All through this paper we employ the term “economic curtailment” as opposed to “technical curtailment”, i.e. required to ensure safety of operations. It does not mean that technical

The optimal level of RES curtailment is the result of a trade-off. On the one hand, not using fully “free” (i.e. with a zero marginal-cost) RES energy may result in higher generation costs, as the substitutes are more expensive. On the other hand, it allows releasing part of the binding technical constraints for inflexible thermal power plants. This trade-off is hence impacted by the marginal costs and the flexibility of the thermal power plants, as well as the variability of RES generation. An additional issue is the very different consequences for the stakeholders involved: consumers, thermal power plants, and RES power plants. The level of curtailment maximising the social welfare might result in losses for the stakeholders offering the RES energy. In the absence of compensations, this optimal level of curtailment will then not be reached. The literature on RES curtailment is still in its infancy, and most studies have been focusing on curtailment of RES in order to solve local congestions or to ensure security of supply: curtailment for higher economic efficiency has seldom been studied. Moreover, existing quantitative studies do not deal with variations in the key parameters such as system flexibility or RES variability, and do not assess the impact on each category of stakeholders. In this article, we build a stylised model of energy production in order to study the mechanisms of RES curtailment for economic reasons. The analysis of the aforementioned trade-off and the consequences on the stakeholders are at the core of our reflection.

First, as we want to focus on the efficiency of operations for a given generation mix, our model is a short-term model and the installed capacity of RES and thermal units are exogenous fixed parameters. It is also considered that consumers do not react to prices and that demand for energy is fixed and inelastic to prices. This demand is met by energy supplied by RES generators and thermal generators. Note that the generators do not adopt any strategic behaviour and offer energy at their marginal generation cost. Second, in order to take into account the impact of the variability of production by RES, we consider two successive production time-periods. Availability of RES is stable within each period but can vary significantly between the two periods. Availability of thermal units can also evolve between two periods as units that have not been generating in the first period are limited in the second time-period due to technical ramping or start-up constraints. Third, it is possible to curtail RES generation in first period. The trade-off is then the one described previously: curtailing RES generation in the first-period leads to higher generation costs in the first-period but allows reducing costs and prices in the second

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curtailment has no economic rationale or that economic curtailment is not grounded in technical fundamentals.

period. Finally, the optimal level of curtailment is established as the one maximising the social welfare, and the impact of a given level of curtailment on each categories of stakeholders is obtained by measuring the variation of their surplus compared to a situation without any curtailment.

Our results confirm that potential savings will be achieved by adopting an optimal level of curtailment, and we describe the relationship between the key parameters driving these benefits. We then show that depending on the level of RES installed capacity and the system flexibility, the price-impact and the volume-impact of RES curtailment can lead to gains or losses for each stakeholders. Interestingly enough, RES can benefit from curtailment even without compensation. In addition, we argue that if decisions to curtail RES are taken by generators, it will result in a sub-optimal level of curtailment. Note that this will be especially the case if thermal generators and RES generators belong to the same utilities. At last, the quality and transparency of data on wind availability will be crucial to ensure that efficient decisions are taken, while RES generators will have significant incentives to manipulate these data.

Our paper is organised as follows: we first review the existing literature in section 2, and highlight the complementarity of our stylised approach with the existing quantitative studies. We then describe the framework of our model and the main assumptions made in section 3. Analytical results are detailed in section 4, while their policy implications are discussed in section 5.

## **2 PREVIOUS WORKS**

The topic of economic RES curtailment has not been dealt with extensively so far, as the share of intermittent RES in the generation mix was not significant, and priority was given to a fast development of these resources.

Most existing works on RES curtailment are empirical studies identifying best practices among the curtailment mechanisms put into place worldwide. This is for instance the case of a collection of reports by the National Renewable Energy Laboratory (Fink, S., C. Mudd, K. Porter and B. Morgenstern 2009, Lew, D., L. Bird, M. Milligan, B. Speer, X. Wang, E. M. Carlini, A. Estanqueiro, D. Flynn, E. Gomez-Lazaro and N. Menemenlis 2013, Rogers, J., S. Fink and K. Porter 2010). These studies highlight the fact that curtailment occurs mainly for technical reasons, when the system encounters transmission or operational constraints. An analysis of different policies for principles of access, including best practices of interruptible connections for wind generation, can also be found in studies by Currie, R.,

B. O'Neill, C. Foote, A. Gooding, R. Ferris and J. Douglas (2011) and Anaya, K. L. and M. Pollitt (2013). Yet their focus is the connection of distributed generation at lower costs for network operators. Note that an interesting exception is a study realised for the Public Service Company of Colorado, revealing that curtailing wind to reduce the cycling costs of coal units would lead to significant benefits (Xcel Energy 2011).

The concept of economic wind curtailment in a context of large-scale integration of electricity from RES is discussed in depth in a qualitative analysis by Brandstätt, C., G. Brunekreeft and K. Jahnke (2011). Through the example of Germany, they argue that removing the restrictions on RES curtailment will be necessary as the system would otherwise feature too much inflexibility both on supply and demand side. They also present a compensation scheme leading to a reduction of total system costs without deteriorating RES revenues. Lastly, the authors argue that such a policy would not conflict with climate policies as higher investments in RES would compensate for the curtailed low-carbon energy.

A few quantitative studies can also be found. Ela, E. (2009) argues that curtailing wind generation can be economically advantageous, using the example of a simple three-bus system. Yet, in his model, these benefits result from the existence of congested lines, with wind generation at a given bus preventing the dispatch of cheaper generators. The constraints resulting from the limited flexibility of thermal generators are not taken into account.

Finally, in a recent paper, Wu, O. and R. Kapuscinski (2013) built a highly detailed power system stochastic optimisation model, and identified a series of efficiency gains thanks to a policy of wind curtailment. They show that the flexibility provided by curtailing RES allows the use of cheap and inflexible thermal units instead of more expensive flexible thermal units. The major components of the savings identified by Wu and Kapuscinski result from avoided cycling costs. According to their study, by curtailing intermittent RES, it is not only possible to lower operation costs but it is also possible to achieve system emission reductions.

Despite these quantitative studies, we believe there is room for further investigation. A limit of the existing numerical quantitative studies is that key parameters such as the system flexibility or the variability of RES are either not considered or set to a single value. Hence, a first significant contribution of our approach based on a stylised model is that we are able to describe the relationship between the pivotal parameters and the optimal level of curtailment. Moreover existing works only assess the variations of overall

generation costs, while the impacts on each stakeholder can be quite different. By using a tailor-made stylised model we are able to focus on optimal curtailment policy for different values of these parameters. Therefore, a second significant contribution of our study is that we are able to analyse how the efficiency gains achieved thanks to curtailment would be shared between the different stakeholders.

### 3 MODEL

#### 3.1 Modelling framework

Our analytical model solves a two-period unit-commitment problem. During each of these periods, a constant fixed demand is to be met by generation from RES and a set of thermal generators. We consider that generators bid their marginal cost and that the price is set as the marginal cost of the marginal unit. Note that our problem is a short-term one, and that the installed capacities are fixed parameters. We assume that the available capacity of RES is lower than the demand so that the price will be set by the marginal cost of the marginal thermal generator.<sup>3</sup>

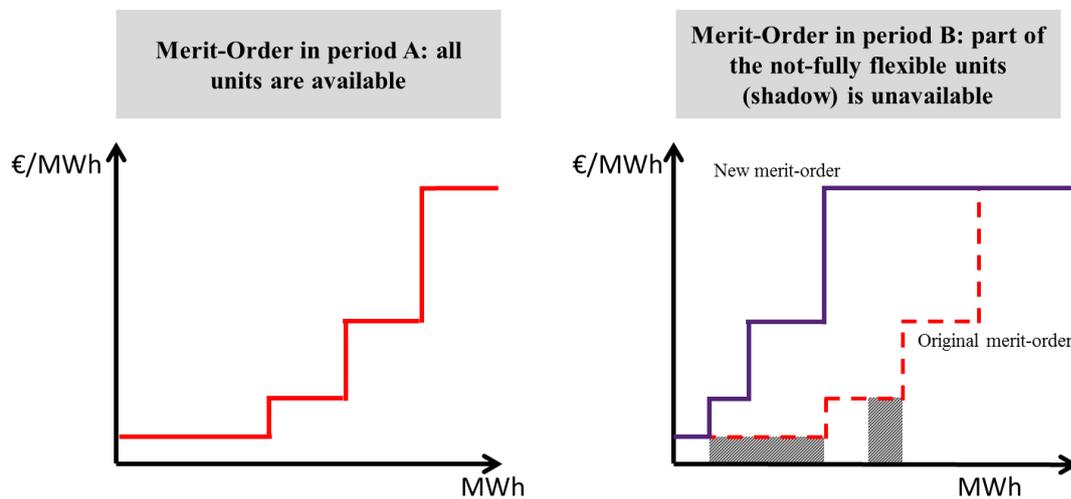
RES generation is variable and uncertain. RES are available for sure in the first period *A*. When curtailment decisions are taken in period *A*, RES availability in period *B* is still uncertain. In the case when RES are not available in period *B*, thermal units will have to adapt their production to meet the demand for energy.<sup>4</sup>

We consider that all the thermal units available in period *A* are also available in period *B*, as their availability should not vary over such a short lapse of time. However, we assume that thermal generators have limited flexibility. The least flexible units not generating in period *A* will not be able to start-up or to ramp-up to full production between the two periods. These inflexible producers will therefore withdraw their offers from the supply function, and the resulting inverse supply function will hence feature a steeper slope in period *B* than in period *A*. This is illustrated in Figure 10.

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<sup>3</sup> We ignore the case of scarcity, when the available thermal capacity is lower than the demand. As a result of the fast development of RES generation, most power systems dealing with a high share of intermittent renewables also typically feature over-supply. Moreover as the cost of scarcity is quite high, it is very likely that these reserve margins will be preserved.

<sup>4</sup> Note that even if there is no uncertainty regarding the availability of RES, our approach remains relevant, as RES generators might be unavailable for sure in period *B*.



**Figure 10: Evolution of the merit-order of thermal units due to start-up and ramping constraints**

As RES units have a marginal cost equal to zero, they should be dispatched first. However, the production is optimised over both time-periods simultaneously. It is possible to curtail RES generation in period A, which will lead to higher costs and a higher electricity price in period A. Inflexible units generating in period A will then be available in period B, leading to lower costs and a lower electricity price in period B. The optimal level of RES curtailment will be a result of this trade-off between generation costs in period A and generation costs in period B.

As of today, the remuneration of RES generators is not purely based on wholesale electricity prices. RES can for instance receive a premium on top of the market-price. When curtailed, the RES generators can also receive a compensation, as described for instance by Brandstät, C., G. Brunekreeft and K. Jahnke (2011). In the absence of demand elasticity, the total welfare is only affected by generation costs. The optimal level of curtailment is therefore not affected by the remuneration and compensation schemes. However, in order to calculate the impact on each stakeholder (i.e. consumers, RES generators, thermal generators), we defined a set of remuneration and compensation schemes: feed-in premium or pure market-based remuneration; full compensation or no compensation.

For simplification, we do not consider the carbon emission costs in our discussion, as we assume these costs could be easily internalised in the variable generation costs of thermal producers.

## 3.2 Model implementation

### *RES availability*

We assume the generation mix features intermittent RES with an available capacity  $K_r < D$ . In the first period  $A$ , RES can generate any amount of energy  $q_r^A \leq K_r$  at a marginal cost equal to zero. We consider two states of nature in period  $B$ . The first state “availability of RES” is denoted by the superscript  $w$  and occurs with probability  $\nu$ ; RES can then generate any amount of energy  $q_r^B \leq K_r$  at a marginal cost equal to zero. The second state “unavailability of RES” is denoted by the superscript  $\bar{w}$  and occurs with probability  $1 - \nu$ ; in this case RES are unable to deliver any energy at all in period  $B$ .

For simplification, we assume in this paper that there are no significant constraints for thermal plants to ramp down.<sup>5</sup> Therefore, when available in period  $B$ , RES will be generating at full potential and  $q_r^B = K_r$  in the first state. For the sake of simplicity we can then denote  $q_r^A$  as  $q_r$ .

### *Thermal generation and price formation*

As the RES available capacity  $K_r$  is not sufficient to meet the demand  $D$ , the remaining energy must be delivered by thermal generators. We assume that the market is perfectly competitive and that generators bid their marginal cost of generating energy as described by Stoft, S. (2002). We consider that generators are fully available in period  $A$  and that the marginal cost  $C_A(q_t^A)$  of generating the quantity of energy  $q_t^A$  with thermal generators in period  $A$  is linear:

$$C_A(q_t^A) = a + b \cdot q_t^A$$

The parameters  $a$  and  $b$  are inputs that depend on the power system properties. The variable  $b$  will be higher when the range of marginal costs of the different generation units will be higher.

The price  $p_A$  is then set as the marginal cost of the most expensive unit needed to meet demand  $D$ . The resulting aggregated inverse supply function in period  $A$  when RES generate the quantity  $q_r$  is then the following:

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<sup>5</sup> The MIT energy initiative (2012) has for instance enlightened us to the fact that modern nuclear plants ramp asymmetrically: it takes them one hour to ramp-down 20% while they might need up to 8 hours to ramp-up to full potential. Moreover, most thermal units feature significant start-up time.

$$p_A(q_r) = a + b \cdot (D - q_r)$$

We also assume, as described in section 3.1, that due to the start-up and ramp-up constraints part of the thermal generators not delivering any energy in period A will not be available in period B. This will result in a steeper cost function and the marginal cost  $C_B(q_t^{\bar{w}}, q_t^A)$  for thermal generators of delivering  $q_t^{\bar{w}}$  in case RES are unavailable will then obey to the following equation graphically described in Figure 11:

$$\begin{cases} C_B(q_t^{\bar{w}}, q_t^A) = a + b \cdot q_t^{\bar{w}} & \text{for } q_t^{\bar{w}} \leq q_t^A \\ C_B(q_t^{\bar{w}}, q_t^A) = a + b \cdot q_t^{\bar{w}} + b \cdot \varphi \cdot (q_t^{\bar{w}} - q_t^A) & \text{for } q_t^{\bar{w}} > q_t^A \end{cases}$$

$\varphi$  is a penalty parameter that reflects the inflexibility of the thermal generators.

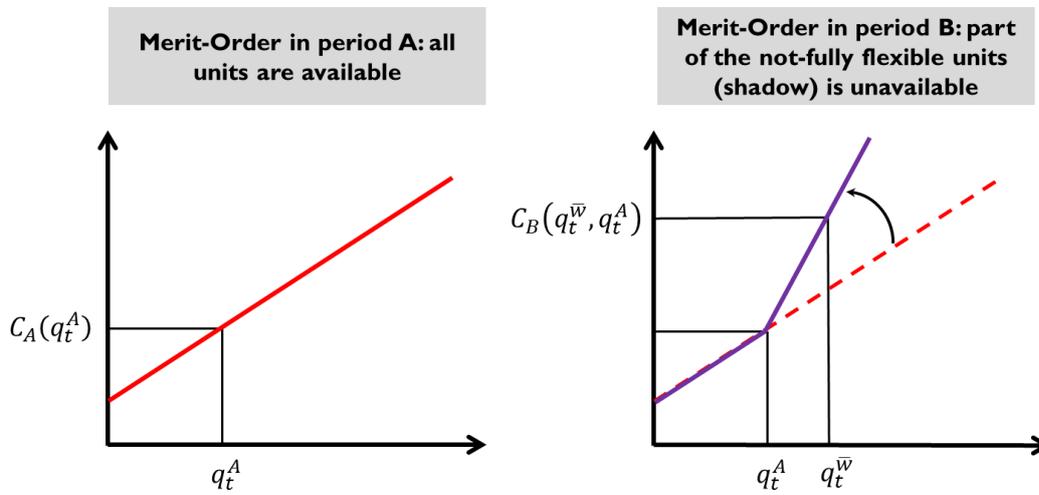


Figure 11: Evolution of the inverse supply function of thermal generators

As demand is equal to  $D$  in both periods, the resulting price  $p^{\bar{w}}(q_r)$  in period B when RES are unavailable and RES have generated the quantity  $q_r$  in period A will therefore be equal to:

$$p^{\bar{w}}(q_r) = a + b \cdot D + b \cdot \varphi \cdot q_r$$

When RES are available in period B, RES will be generating at full potential  $K_r$ . The amount of energy generated by thermal generators  $D - K_r$  will hence be lower or equal to the amount of energy generated by thermal generators in period A. The price will then be equal to:

$$p^w = a + b \cdot (D - K_r)$$

## **Remuneration and compensation scheme for RES**

In period  $A$ , RES receive for the energy generated  $q_r$  remuneration  $R_g$  per unit of energy, based on the market price  $p_A(q_r)$  and possibly a premium  $Z$ . In the case of a remuneration based on market prices only, the premium  $Z$  is equal to 0. In the case of a remuneration that is made of both market-revenue and a premium (e.g. Feed-in premium),  $Z > 0$ .

RES generators can also receive compensation for the energy curtailed  $K_r - q_r$ . The remuneration  $R_c$  per unit of energy curtailed is then a by definition a share  $(1 - \alpha)$  of the market price component, and a share  $(1 - \beta)$  of the premium component. Depending on the compensation schemes,  $\alpha$  and  $\beta$  are equal to 0 (full compensation of the related component) or 1 (no compensation of the related component). In this paper we focus on two extreme cases. Under *case #1*, RES generators do not receive any compensation at all:  $\alpha = \beta = 1$ . Under *case #2*, RES generators receive full compensation when curtailed:  $\alpha = \beta = 0$ .

$$\begin{cases} R_g = p_A(q_r) + Z & \text{per unit of energy generated (i. e. not curtailed)} \\ R_c = (1 - \alpha) \cdot p_A(q_r) + (1 - \beta) \cdot Z & \text{per unit of energy curtailed} \end{cases}$$

Where  $Z \geq 0$  and  $(\alpha, \beta) \in \{0,1\}^2$

In period  $B$ , RES do not receive any remuneration if unavailable, and receive a remuneration  $R^w$  per unit of energy generated if available, with  $R^w = p^w(q_r) + Z$ .

## **4 ANALYTICAL RESULTS**

### **4.1 Optimal level of curtailment**

#### ***Optimal level of curtailment***

In this section, we determine the level of curtailment maximising the social welfare. The optimal level of curtailment is defined as the one in which the production  $q_r$  by RES in period  $A$  maximises the social welfare  $S(q_r)$  across period  $A$  and period  $B$ , for both states of nature. This problem can be simplified as demand is fixed and inelastic in both time-periods. Any variation of the consumer surplus is then automatically compensated by a variation of generators surplus: social welfare is maximised when the generation costs across both time periods  $C(q_r)$  are minimised.

The optimal level of production  $\tilde{q}_r$  is therefore defined as:

$$\tilde{q}_r = \arg \min_{q_r} C(q_r)$$

Subject to  $0 \leq q_r \leq K_r$

Where  $C(q_r) = \int_{q_r}^D [C_A(x - q_r)] dx + v \cdot \int_{K_r}^D [C_B(x - K_r, D - q_r)] dx + (1 - v) \cdot \int_0^D [C_B(x, D - q_r)] dx$

**Proposition 1.** The optimal level of curtailment is independent of the remuneration and compensation schemes for RES generators, and is such that RES generate in period A the quantity  $\tilde{q}_r$  :

$$\begin{cases} \tilde{q}_r = \frac{a + bD}{b \cdot (1 + \varphi \cdot (1 - \nu))} & \text{for } K_r > \frac{a + bD}{b \cdot (1 + \varphi \cdot (1 - \nu))} \\ \tilde{q}_r = K_r & \text{for } K_r \leq \frac{a + bD}{b \cdot (1 + \varphi \cdot (1 - \nu))} \end{cases}$$

Savings  $\Delta S$  are such that:

$$\Delta S = S(\tilde{q}_r) - S(K_r) = \frac{(1 + \varphi(1 - \nu))}{2} \times (K_r - \tilde{q}_r)^2$$

When the available capacity is high and flexibility is low, savings can be achieved by curtailing RES generation in period A. The incentives to curtailment decrease with the flexibility of the system (represented by factor  $\varphi$ ) and increase with the variability of the system (represented by  $1 - \nu$ ).

Note that in the simple case in which the cheapest thermal units have very low marginal costs (i.e.  $a \approx 0$ ) the threshold is equal to  $\frac{D}{1 + \varphi \cdot (1 - \nu)}$ . Without inflexibility costs ( $\varphi = 0$ ) or variability ( $1 - \nu = 0$ ), RES would generate as much as available, until demand  $D$  is met. Yet, as there are flexibility issues, only a smaller share of the demand  $\frac{D}{1 + \varphi \cdot (1 - \nu)}$  should be generated by RES.

The level of curtailment  $\tilde{q}_r$  maximising the social welfare is represented in Figure 12.

### ***Curtailment level maximising the profits of RES generators***

In this section we determine the curtailment level maximising the profits of RES generators. These profits are only impacted in period *A*: in period *B* RES are either unavailable (and hence do not receive anything) or are available, fully generating, and receiving a market price  $p^w$  and potentially a premium  $Z$  that are independent from the curtailment level.

**Proposition 2.** The level of curtailment maximising the profits of RES generators is such that RES generate the quantity  $q_R^*$  in period *A*.

2.1) Case #1: Feed-in Premium / No compensation

$$\begin{cases} q_R^* = \frac{Z + a + bD}{2 \cdot b} & \text{for } K_r \geq \frac{Z + a + bD}{2 \cdot b} \\ q_R^* = K_r & \text{for } K_r \leq \frac{Z + a + bD}{2 \cdot b} \end{cases}$$

2.2) Case #2: Feed-in premium /Full compensation

$$\forall Z \geq 0, q_R^* = 0$$

In the absence of compensation, the optimal level of curtailment for RES generators is not null when the available capacity is higher than a given threshold. RES are willing to reduce their volume of production, as they benefit from the consequential rise of wholesale prices. The production level is independent from the system flexibility and the RES variability, and is only affected by the premium and the nature of the costs of thermal generators. RES generators tend to over-curtail their production when flexibility is high and variability low; they tend to under-curtail their production when flexibility is low and variability is high. A higher premium leads to lower curtailment as the gains from higher prices are partially offset by the loss of the premium. A steeper curve of marginal costs of thermal generators gives more incentives to curtailment as the price effect will be higher for a given volume of curtailment.

In the case RES generators get full compensation when curtailed, they will have an incentive to over-curtail, as they will benefit from the resulting higher prices.

The level of curtailment maximising the profit of RES generators is represented in Figure 12, for the two compensation schemes.

### ***Curtailement level maximising the profits of all generators***

In this section we determine the curtailment level maximising the profits of both thermal and RES generators, for instance when they are integrated within a large utility.

**Proposition 3.** The level of curtailment maximising the profits of both RES and thermal generators is such that RES generate in period A the quantity  $q_{R+T}^*$

3.1) Case #1: Feed-in Premium / No compensation

$$\left\{ \begin{array}{ll} q_{R+T}^* = D + \frac{Z + a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} & \text{for } K_r \geq D + \frac{Z + a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} \\ q_{R+T}^* = K_r & \text{Otherwise} \end{array} \right.$$

3.2) Case #2: Feed-in premium /Full compensation

$$\left\{ \begin{array}{ll} q_{R+T}^* = 0 & \text{for } (1 - \nu) \cdot \varphi \in \left[ 0; 1 + \frac{K_r}{D} \right] \\ q_{R+T}^* = D - \frac{K_r}{(1 - \nu) \cdot \varphi - 1} & \text{for } (1 - \nu) \cdot \varphi \in \left[ 1 + \frac{K_r}{D}; 1 + \frac{K_r}{D - K_r} \right] \\ q_{R+T}^* = K_r & \text{for } (1 - \nu) \cdot \varphi \geq 1 + \frac{K_r}{D - K_r} \end{array} \right.$$

Once again, in the absence of compensation, the level of curtailment maximising the profits of generators is not null. Moreover, when the available RES capacity is high and the curve of the marginal costs of thermal generators steep, the incentives to curtail wind generation are then higher when the system flexibility is high or the variability is low, as both RES generators and thermal generators benefit from higher prices in period A. Note that the social welfare increases in case of curtailment when the system flexibility is low and the variability high: producers therefore have incentives to curtail RES that go against the system benefits. Incentives to over-curtailment when flexibility is high and variability is low can be partially offset by the existence of a premium, as this premium is lost in case of over curtailment. Yet such a premium also leads to under-curtailment when the system flexibility is low and the variability is high.

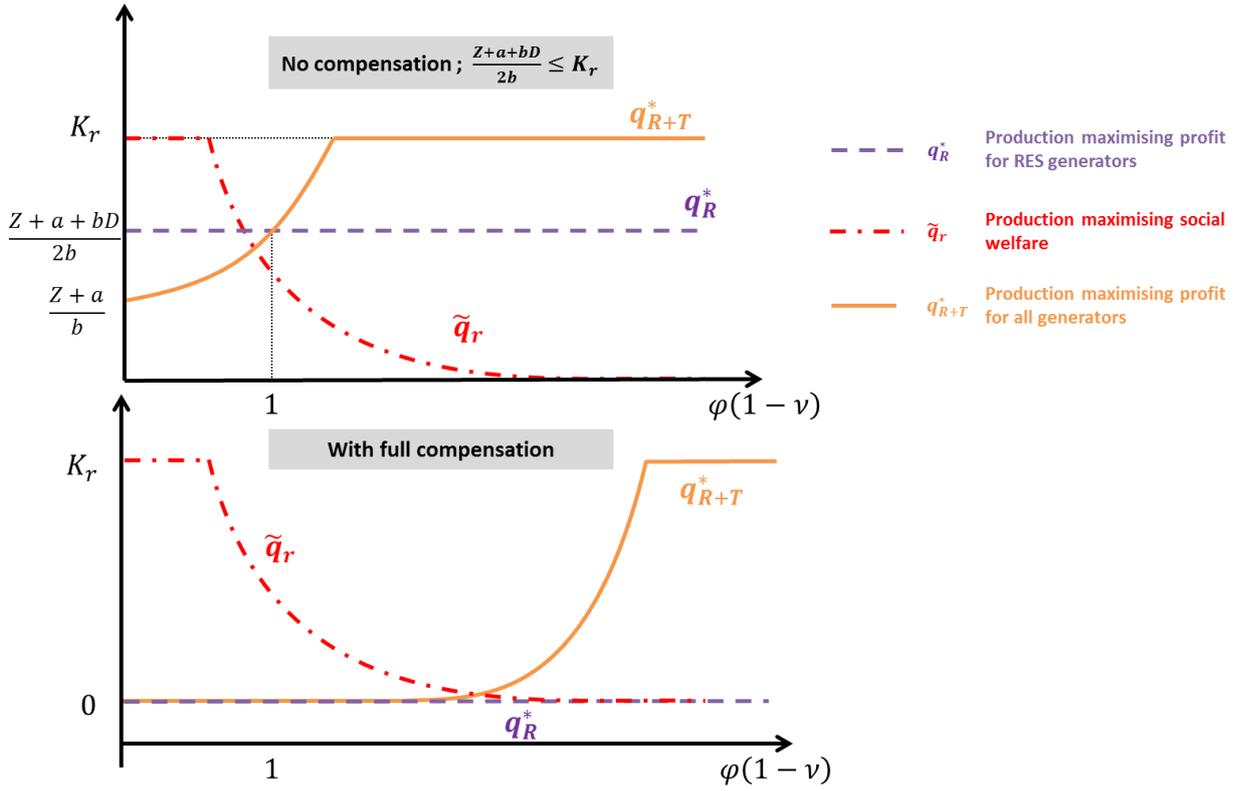


Figure 12: Optimal level of curtailment and level of curtailment maximising the profits of generators, with and without compensation.

In the case RES generators get compensation when curtailed, the incentives to over-curtail are even higher than without compensation since the RES generators keep receiving the premium, and the price-impact occurs without impacting the volume impact. For high flexibility and low variability, the generators would then rather withhold their whole RES production.

The level of curtailment maximising the profit of both kinds of generators is represented for the two compensation schemes in Figure 12.

**Proposition 4.** In the case when RES do not receive any premium and when no compensation is provided to curtailed RES, the level of curtailment maximising the profits of both RES and thermal generators is further from the optimal level of curtailment than the level of curtailment maximising the profits of RES only.

$$Z = 0, \alpha = 1 \Rightarrow |\tilde{q}_r - q_R^*| \leq |\tilde{q}_r - q_{R+T}^*|$$

$$\text{And more specifically } \begin{cases} (1-v) \cdot \varphi \leq 1 \Rightarrow \tilde{q}_r \geq q_R^* \geq q_{R+T}^* \\ (1-v) \cdot \varphi \geq 1 \Rightarrow \tilde{q}_r \leq q_R^* \leq q_{R+T}^* \end{cases}$$

When no compensation is provided to RES generators and when they do not receive any premium for the energy generated on top of wholesale prices, integrated RES generators and conventional generators will have higher incentives to deviate from the optimal level of generation than RES alone.

On-the-side payments to RES, such as feed-in premium and compensation schemes affect the behaviour of RES generators, and integration with thermal generators can then be beneficial.

#### 4.2 Impact of curtailment on each stakeholder

In this section, we look at the impact of optimal curtailment on the three categories of stakeholders identified in this study: consumers, RES generators and thermal generators. Indeed, even though the optimal level of curtailment increases the total social welfare, whether these stakeholders will benefit or lose is depends highly upon the system flexibility, available RES capacity, and generation volatility.

We denote  $\Delta S_c$  (respectively  $\Delta S_R$  and  $\Delta S_T$ ) the variations in the surplus of consumers (respectively RES generators and thermal generators) resulting from the switch from no-curtailment policy to optimal-curtailment policy.

**Proposition 5.1.** In the case when RES generators do not receive any compensation when curtailed, i.e.  $\alpha = \beta = 1$  then:

$$\begin{aligned}\Delta S_c \geq 0 &\Leftrightarrow (1 - \nu) \cdot \varphi \geq 1 - \frac{Z}{D \cdot b} \\ \Delta S_R \geq 0 &\Leftrightarrow K_r \geq \frac{1}{b} \left( Z + (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} \right) \\ \Delta S_T \geq 0 &\Leftrightarrow (1 - \nu) \cdot \varphi \leq 1\end{aligned}$$

Consumers will benefit from curtailment if flexibility is low and variability is high, while thermal generators will benefit from optimal curtailment if flexibility is high and variability is low. This will not be affected by the available capacity of RES.

However, RES benefit from an optimal level of curtailment, even without compensation, when available capacity is high: the higher-price impact will then offset the reduced-volume impact.

When RES generators receive a higher premium, curtailment leads to further benefits for consumers and higher losses for RES generators.

This result is illustrated in Figure 13, in the simple case when RES do not get any premium on top of wholesale prices (i.e.  $Z = 0$ ). Note that in the area  $D$ , only consumers will benefit from optimal curtailment.

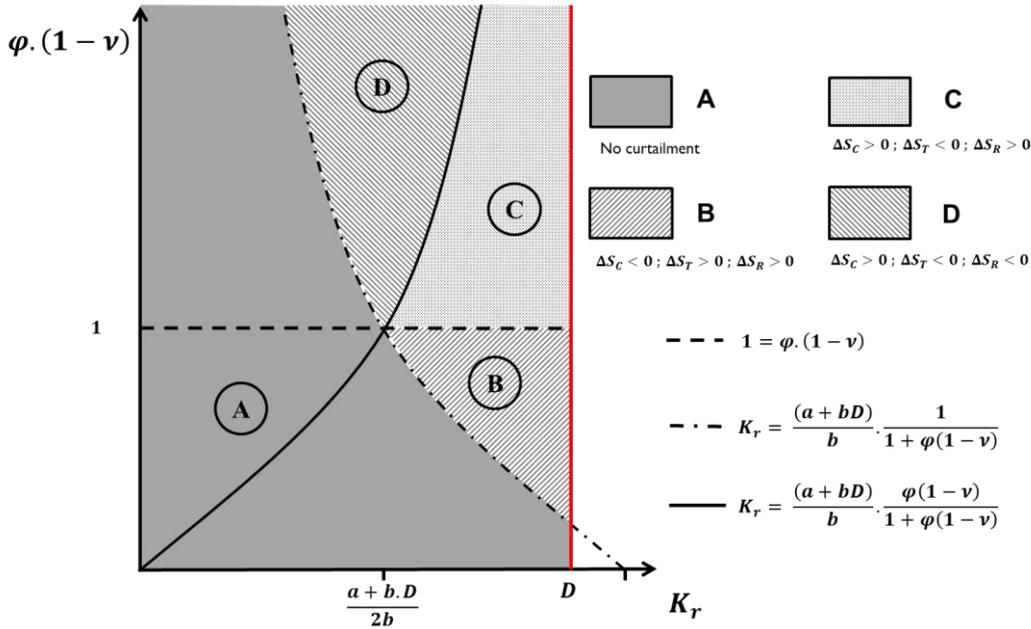


Figure 13: Impact of optimal curtailment on the different stakeholders in case no compensation and no premium are paid to RES generators

**Proposition 5.2.** In the case when RES generators receive full compensation when curtailed, i.e.  $\alpha = \beta = 0$  then:

$$\Delta S_C \geq 0 \Leftrightarrow (1 - \nu) \cdot \varphi \geq \frac{1}{2} \times \left[ \frac{a + b \cdot D}{b \cdot D} + \sqrt{\left( \frac{a + b \cdot D}{b \cdot D} \right)^2 + 4} \right]$$

$$\Delta S_R \geq 0$$

$$\Delta S_T \geq 0 \Leftrightarrow (1 - \nu) \cdot \varphi \leq 1$$

Once again, consumers will benefit from curtailment if flexibility is low and variability is high, while thermal generators will benefit from optimal curtailment if flexibility is high and variability is low. This will not be affected by the available capacity of RES or by the premium value. As they receive compensation when curtailed, RES generators will always benefit from optimal curtailment. These results are illustrated in Figure 14.

Note that in this case, the sign of the impact on the different stakeholders is not affected by the available RES capacity or by the premium paid to RES generators.

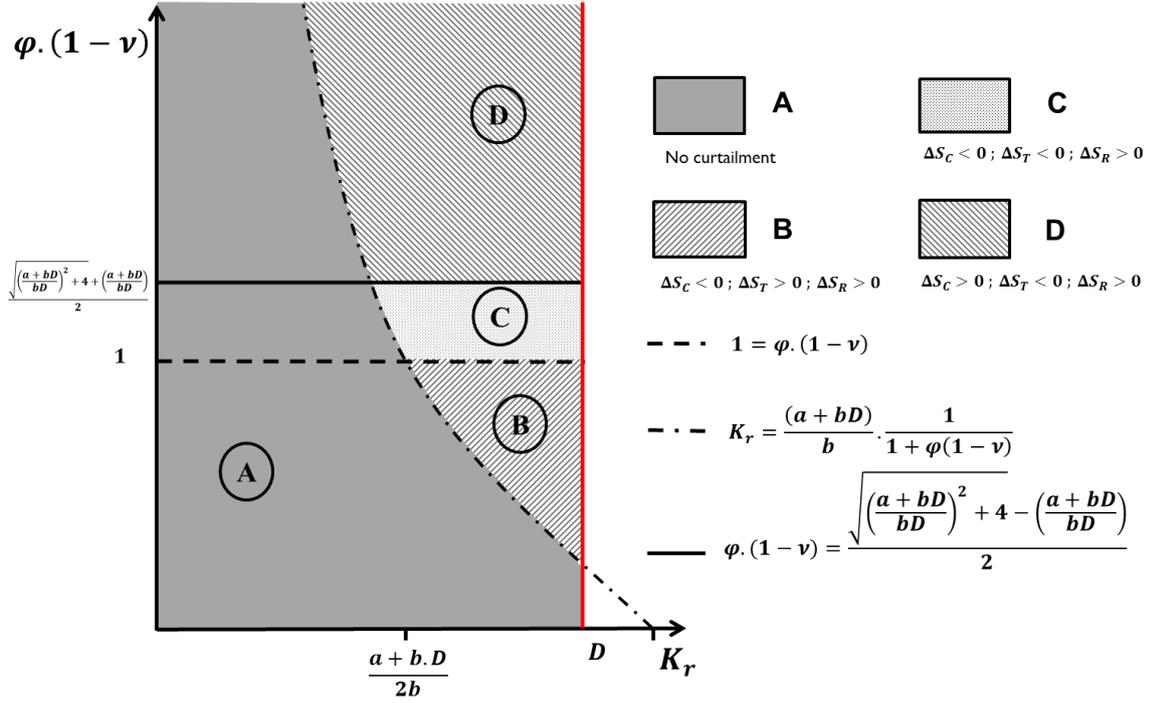


Figure 14: Impact of optimal curtailment on the different stakeholders in case full compensation is paid to RES generators

### 4.3 Extra costs as a result of lack of information

In this section, we consider that the level of curtailment is set by an agent (e.g. the Transmission System Operator) aiming at maximising the social welfare based on variability information provided by RES generators. RES will have incentives to manipulate this information in order to increase their profits.

**Proposition 6.** Similarly, in case the optimal level of curtailment is set based on an incorrect estimation  $1 - \hat{v}$  of the variability  $1 - v$ , variation of the social welfare compared to the optimal curtailment level will be equal to:

$$\Delta(v, \hat{v}) = S(\hat{q}_r) - S(\tilde{q}_r) = -\frac{(a + b \cdot D)^2}{2 \cdot b} \cdot \frac{\varphi^2}{(1 + (1 - v) \cdot \varphi)^3} \cdot (\hat{v} - v)^2$$

In case, RES do not get any compensation, variation of the profits of RES generators will be equal to:

$$\Delta_R(v, \hat{v}) = S_R(\hat{q}_r) - S_R(\tilde{q}_r) = \frac{(a + b \cdot D)}{b} \cdot \frac{\varphi \cdot (v - \hat{v})}{(1 + (1 - v) \cdot \varphi)^2} \cdot \left( \beta \cdot Z + (a + b \cdot D) \cdot \frac{(1 - \varphi \cdot (1 - v))}{1 + \varphi \cdot (1 - v)} \right)$$

In particular, for  $Z = 0$ , when RES do not receive any premium,

$$\Delta_R(v, \hat{v}) = \frac{(a + b \cdot D)^2}{b} \cdot \frac{\varphi \cdot (1 - \varphi \cdot (1 - v))}{(1 + (1 - v) \cdot \varphi)^3} \cdot (v - \hat{v})$$

$$\begin{cases} \text{For } (1 - v) \cdot \varphi \leq 1, (1 - \hat{v}) \geq (1 - v) \Rightarrow \Delta_R(v, \hat{v}) \geq 0 \text{ and } \Delta(v, \hat{v}) \leq 0 \\ \text{For } (1 - v) \cdot \varphi \geq 1, (1 - \hat{v}) \leq (1 - v) \Rightarrow \Delta_R(v, \hat{v}) \geq 0 \text{ and } \Delta(v, \hat{v}) \leq 0 \end{cases}$$

When variability is low and flexibility is high, RES generators will tend to provide overestimations of variability (i.e. higher values for  $1 - v$ ) leading to over-curtailment of RES generation. Oppositely, when variability is high and flexibility is low, RES generators will tend to provide underestimations of variability (i.e. lower values for  $1 - v$ ) leading to under-curtailment of RES generation.

A penalty imposed on RES generators equal to  $-\Delta_R(v, \hat{v})$  could correct these incentives when the forecasts delivered differ from the realised output.

## 5 RESULTS DISCUSSION

### 5.1 Optimal level of curtailment and distributional impacts

**Conclusion 1:** *It is rationale to curtail RES generation if flexibility is low and available RES capacity high.*

From proposition 1, we are able to identify an optimal level of curtailment when the available RES capacity is higher than a threshold decreasing as the flexibility of the system and as the variability of the RES generation increases. For a stable thermal generation mix, curtailment will hence become beneficial as the penetration of RES becomes significant. Curtailment policies will then become increasingly relevant in a context of large-scale development of renewables. The priority of dispatch to RES as it exists today in Europe should then be reassessed. In case variability is high and flexibility low, savings can be significant.

This level of curtailment does not depend on the nature of RES remuneration, nor on whether RES get compensated, as it only reflects the generation costs, and the trade-off between making the most of available RES with zero marginal cost and allowing cheaper inflexible thermal units to generate energy.

***Conclusion 2: The impact of curtailment is different for each stakeholder and varies with the available RES capacity and the system flexibility. In particular RES can benefit from curtailment even without a compensation scheme.***

From propositions 5.1 and 5.2, we see that the surplus of the main stakeholders is affected in very diverse ways by curtailing RES generation. The benefits of generators are subject to a price-impact, as prices initially increase when RES generation is curtailed, and a volume-impact. Thermal generators tend to benefit from curtailment when flexibility is high and volatility is low, while consumers benefit from curtailment when flexibility is low and volatility is high. Interestingly enough, RES can benefit from curtailment even in the case when they do not receive any compensation. This is the case when the available capacity is important enough so that the losses from lower generation are offset by higher prices.

While the optimal level of curtailment is not impacted by the remuneration and compensation schemes of RES, it drives the redistribution of the resulting benefits. When RES do not receive any compensation, the sign of the impact of curtailment switches as more generating units are available. The sign of the impact on the surplus of consumers and RES generators is also affected as the premium paid to RES on top of the wholesale price is affected. It implies that any curtailment scheme will have to be versatile enough to adapt to changing circumstances.

Providing compensation to curtailed RES generators allows them to benefit from curtailment whatever the available capacity, and hedge the different stakeholders against the variability of the premium. Note that even in the case of compensation to RES, consumers (who pay this compensation) can benefit from the reduced generation costs due to an optimal level of curtailment.

## **5.2 Delivering the optimal level of curtailment**

***Conclusion 3: Leaving curtailment decisions to generators will lead to sub-optimal levels of curtailment. This will especially be the case if RES and thermal generators are integrated within a single company.***

Generators (either RES or thermal generators) can lose from curtailment and the level of curtailment maximising their profits can be substantially different from the optimal level of curtailment, as shown in proposition 2 and 3. Generators tend to over-curtail generation when the system flexibility is high and RES variability is low, while they tend to under-curtail generation when the system flexibility is low and RES variability is high. There are cases, as illustrated in Figure 13 in which only consumers will benefit from an optimal level

of curtailment. It is then unlikely this optimal level of curtailment could be reached through decentralised decisions in a market from which consumers are absent. These results suggest that the decision regarding the amount of RES energy to be curtailed should be taken by an agent such as the transmission system operator.

Proposition 4 reveals that, in the absence of compensation for curtailed generation, the level of curtailment maximising the profits of integrated RES and thermal generators is even further from the optimal level of curtailment than the one maximising the profits of RES alone. We can conclude that when both kinds of generators are concentrated within a single utility, special attention should be paid to the level of curtailment implemented.

***Conclusion 4: If the decision regarding the level of curtailment is taken by the system operator, a problem of asymmetry of information will occur. Incentives should be put into place to ensure the quality of production forecasts communicated by producers. Alternatively centralised forecasting should be implemented.***

Even when a decision is decentralised to the system operator, RES could manipulate the information they provide to the system operator so as to influence its decision on the curtailment level. Proposition 6 shows that when variability is slow and flexibility is high, RES generators will have incentives to provide estimates of variability (i.e. in our context, the likelihood of a rapid reduction of RES availability) that are too high. On the other hand, RES generators will have incentives to provide too low estimates of variability when variability is high and flexibility is low.

This problem can be solved by exposing intermittent RES to the costs resulting from deviations from their declared schedule. Measures similar to the EU regulation 1227/2011 on wholesale energy market integrity and transparency (REMIT) can also be implemented. This regulation compels participants to disclose any insider information that could significantly affect wholesale power prices, such as the unavailability of generation units. However, in the case of REMIT, only plants with an installed capacity higher than 100 MW will be concerned, which excludes most of the RES installations. Such shortcomings will be an obstacle to the efficient management of RES production.

Alternatively, the TSO can centralise forecasting activities, to make sure that it has access to quality forecast. Pérez-Arriaga, I. J. and C. Batlle (2012) already argued that the benefits of aggregating data justify centralisation of wind forecasting activities.

## **ACKNOWLEDGEMENTS**

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## APPENDIXES

### A.1 Nomenclature

Variable	Meaning
$D$	Demand for energy in both periods
$q_r$	Quantity of energy generated by RES in period A
$K_r$	Potential for energy generation by RES in period A and B when available
$C_A(q)$	Marginal cost for thermal generators of generating the quantity of energy $q$ in period A
$C_B(q_2, q_1)$	Marginal cost for thermal generators of generating the quantity of energy $q_2$ in period B when they generated $q_1$ in period A
$C(q)$	Total expected generation costs when RES generated $q$ during period A
$p_A(q)$	Price in period A when RES generated $q$ during period A
$p^{\bar{w}}(q)$	Price in period B when RES generated $q$ during period A and RES are not available in period B.
$p^w$	Price in period B when RES are available in period B.
$a$	Constant parameter of the inversed supply-function for thermal generators
$b$	Slope of the inversed supply-function for thermal generators
$\varphi$	Flexibility penalty for non-committed RES generators
$\nu$	Probability that RES are available in period B
$S(q)$	Total economic surplus when RES generated $q$ during period A
$S_T^A(q)$	Economic surplus of thermal generators in period A when RES generated $q$ during period A
$S_T^B(q)$	Economic surplus of thermal generators in period B when RES generated $q$ during period A
$S_R(q)$	Economic surplus of RES generators when RES generated $q$ during period A
$S_{T+R}(q)$	Economic surplus of all generators when RES generated $q$ during period A
$\tilde{q}_r$	Level of production of RES in period A when curtailment is optimal
$q_R^*$	Level of production of RES in period A maximising RES surplus
$q_{R+T}^*$	Level of production of RES in period A maximising generators surplus

## A.2. Proof of proposition 1

As demand is not flexible, social welfare is maximised when the generation costs are minimum. The optimal level of production  $\tilde{q}_r$  is then defined as:

$$\tilde{q}_r = \arg \min_{q_r} C(q_r)$$

Subject to  $0 \leq q_r \leq K_r$

Where  $C(q_r) = \int_{q_r}^D [C_A(x - q_r)] dx + v \cdot \int_{K_r}^D [C_B(x - K_r, D - q_r)] dx + (1 - v) \cdot \int_0^D [C_B(x, D - q_r)] dx$

$$C(q_r) = \int_0^{D-q_r} [C_A(x)] dx + v \cdot \int_0^{D-K_r} [C_B(x, D - q_r)] dx + (1 - v) \cdot \int_0^D [C_B(x, D - q_r)] dx \quad (1)$$

By definition ,  $K_r \geq q_r$  and  $D - K_r \leq D - q_r$

$$C(q_r) = \int_0^{D-q_r} [a + b \cdot x] dx + v \cdot \int_0^{D-K_r} [a + b \cdot x] dx + (1 - v) \cdot \left( \int_0^{D-q_r} [a + b \cdot x] dx + \int_{D-q_r}^D [a + b \cdot x + b \cdot \varphi \cdot (x - (D - q_r))] dx \right)$$

$$C(q_r) = \int_0^{D-q_r} [a + b \cdot x] dx + v \cdot \int_0^{D-K_r} [a + b \cdot x] dx + (1 - v) \cdot \left( \int_0^D [a + b \cdot x] dx + \int_0^{q_r} [b \cdot \varphi \cdot x] dx \right)$$

$$\Rightarrow \frac{dC(q_r)}{dq_r} = -(a + b \cdot (D - q_r)) + (1 - v) \cdot b \cdot \varphi \cdot q_r \quad (2)$$

$$\Rightarrow \begin{cases} \tilde{q}_r = \frac{a + bD}{b \cdot (1 + \varphi(1 - v))} & \text{for } K_r > \frac{a + bD}{b \cdot (1 + \varphi(1 - v))} \\ \tilde{q}_r = K_r & \text{for } K_r \leq \frac{a + bD}{b \cdot (1 + \varphi(1 - v))} \end{cases} \quad (3)$$

Moreover, savings when curtailing RES generation from  $K_r$  to  $\tilde{q}_r$  will then be equal to:

$$\Delta S = S(\tilde{q}_r) - S(K_r) = C(K_r) - C(\tilde{q}_r) = \int_{\tilde{q}_r}^{K_r} \frac{dC(q_r)}{dq_r} dq_r$$

$$\Rightarrow \Delta S = \frac{(1 + \varphi(1 - v))}{2} \times (K_r - \tilde{q}_r)^2 \quad (4)$$

### A.3. Proof of proposition 2

The surplus of wind generators in period  $B$  is not impacted by the curtailment level, as the output is equal to 0 in case these resources are not available, and as it is always fully dispatched at the same prices in case these resources are available.

Therefore, the production  $q_R^*$  of RES in period  $A$  maximising the profits of RES generators is defined as:

$$q_R^* = \arg \max_{q_r} S_R^A(q_r)$$

Subject to  $0 \leq q_r \leq K_r$

Where  $S_R^A(q_r)$  is the surplus of RES generators in period  $A$  :

$$S_R^A(q_r) = \int_0^{q_r} [p_A(q_r) + Z] dq + \int_{q_r}^{K_r} [(1 - \alpha) \cdot p_A(q_r) + (1 - \beta) \cdot Z] dq \quad (5)$$

And  $p_A(q_r)$  is the marginal cost of generating of the most expensive thermal unit called:

$$p_A(q_r) = a + b \cdot (D - q_r)$$

$$\Rightarrow \frac{dS_R(q_r)}{dq_r} = \beta \cdot Z + \alpha \cdot (a + b \cdot D) - (1 - \alpha) \cdot b \cdot K_r - 2 \cdot \alpha \cdot b \cdot q_r \quad (6.1)$$

Case #1: Feed-in Premium, with no compensation

$$\alpha = 1 ; \beta = 1$$

$$\Rightarrow \begin{cases} q_R^* = \frac{Z + a + bD}{2 \cdot b} & \text{for } K_r \geq \frac{Z + a + bD}{2 \cdot b} \\ q_R^* = K_r & \text{for } K_r \leq \frac{Z + a + bD}{2 \cdot b} \end{cases} \quad (6.2)$$

Case #2: Feed-in Premium, with full compensation

$$\alpha = 0; \beta = 0$$

(6.3)

$$\begin{aligned} \Rightarrow \forall q_r \in [0, q_r], \frac{dS_R(q_r)}{dq_r} &= -b \cdot K_r < 0 \\ \Rightarrow q_r^* &= 0 \end{aligned}$$

#### A.4. Proof of proposition 3

For a RES generation equal to  $q_r$  in period A, the surplus of thermal generators  $S_T^A(q_r)$  in period A is equal to:

$$S_T^A(q_r) = \int_0^{D-q_r} [p_A(q_r) - C_A(q)] dq$$

Where  $p_A(q_r) = a + b \cdot (D - q_r)$  and  $C_A(q) = a + b \cdot (D - q)$

$$\Rightarrow \frac{dS_T^A(q_r)}{dq_r} = -b \cdot (D - q_r) \quad (7.1)$$

The profit of conventional generators in phase B only depends on the curtailment level in period A in the case in which there is no wind. For a RES generation equal to  $q_r$  in period A, the surplus of thermal generators  $S_T^B(q_r)$  in period B is equal to:

$$S_T^B(q_r) = (1 - \nu) \left[ D \cdot p^{\bar{\omega}}(q_r) - \int_0^D C_B(q, D - q_r) dq \right] + \nu \cdot \lambda(q_r)$$

With  $\frac{d\lambda(q_r)}{dq_r} = 0$

And where by definition:

$$p^{\bar{\omega}}(q_r) = a + b \cdot D + b \cdot \varphi \cdot q_r$$

$$\begin{cases} C_B(q_t^{\bar{\omega}}, q_t^A) = a + b \cdot q_t^{\bar{\omega}} & \text{for } q_t^{\bar{\omega}} \leq q_t^A \\ C_B(q_t^{\bar{\omega}}, q_t^A) = a + b \cdot q_t^{\bar{\omega}} + b \cdot \varphi \cdot (q_t^{\bar{\omega}} - q_t^A) & \text{for } q_t^{\bar{\omega}} > q_t^A \end{cases}$$

$$\Rightarrow \frac{dS_T^B(q_r)}{dq_r} = (1 - \nu) \cdot \varphi \cdot b \cdot (D - q_r) \quad (7.2)$$

The surplus  $S_{T+R}(q_r)$  of both thermal generators and RES generators is such that:

$$\frac{dS_{T+R}(q_r)}{dq_r} = \frac{dS_R(q_r)}{dq_r} + \frac{dS_T^A(q_r)}{dq_r} + \frac{dS_T^B(q_r)}{dq_r}$$

From equations 6.1, 7.1 and 7.2,

$$\begin{aligned} \frac{dS_{T+R}(q_r)}{dq_r} = & ((1 - \nu) \cdot \varphi - 1) \cdot b \cdot (D - q_r) + \beta \cdot Z + \alpha \cdot (a + b \cdot D) - (1 - \alpha) \cdot b \cdot K_r \\ & - 2 \cdot \alpha \cdot b \cdot q_r \end{aligned} \quad (8)$$

Case #1: Feed-in Premium, with no compensation

$$\alpha = 1; \beta = 1$$

$$\begin{aligned} \frac{dS_{T+R}(q_r)}{dq_r} &= ((1 - \nu) \cdot \varphi - 1) \cdot b \cdot (D - q_r) + \beta \cdot Z + (a + b \cdot D) - 2 \cdot b \cdot q_r \\ \Rightarrow \begin{cases} q_{R+T}^* = D + \frac{Z + a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} & \text{for } K_r \geq D + \frac{Z + a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} \\ q_{R+T}^* = K_r & \text{Otherwise} \end{cases} \end{aligned} \quad (9.1)$$

Case #2: Feed-in Premium, with full compensation

$$\alpha = 0; \beta = 0$$

$$\begin{aligned} \frac{dS_{T+R}(q_r)}{dq_r} &= ((1 - \nu) \cdot \varphi - 1) \cdot b \cdot (D - q_r) - b \cdot K_r \\ \Rightarrow \begin{cases} q_{R+T}^* = 0 & \text{for } (1 - \nu) \cdot \varphi \in \left[0; 1 + \frac{K_r}{D}\right] \\ q_{R+T}^* = D - \frac{K_r}{(1 - \nu) \cdot \varphi - 1} & \text{for } (1 - \nu) \cdot \varphi \in \left[1 + \frac{K_r}{D}; 1 + \frac{K_r}{D - K_r}\right] \\ q_{R+T}^* = K_r & \text{for } (1 - \nu) \cdot \varphi \geq 1 + \frac{K_r}{D - K_r} \end{cases} \end{aligned} \quad (9.2)$$

### A.5. Proof of proposition 4

In the case when RES do not receive any premium (i.e.  $Z = 0$ ) and when no compensation is provided to curtailed RES (i.e.  $\alpha = 1$ ), the level of curtailment  $q_R^*$  maximising the profit of RES generators is according to equation 6.2:

$$\begin{cases} q_R^* = \frac{a + bD}{2.b} & \text{for } K_r \geq \frac{a + bD}{2.b} \\ q_R^* = K_r & \text{for } K_r \leq \frac{a + bD}{2.b} \end{cases} \quad (10.1)$$

Similarly, the level of curtailment  $q_{R+T}^*$  maximising the profit of both thermal and RES generators is according to equation 9.1:

$$\begin{cases} q_{R+T}^* = D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} & \text{for } K_r \geq D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} \\ q_{R+T}^* = K_r & \text{Otherwise} \end{cases} \quad (10.2)$$

Finally, the optimal level of curtailment  $\tilde{q}_r$  is according to equation 3 such that:

$$\begin{cases} \tilde{q}_r = \frac{a + bD}{b(1 + \varphi(1 - \nu))} & \text{for } K_r > \frac{a + bD}{b(1 + \varphi(1 - \nu))} \\ \tilde{q}_r = K_r & \text{for } K_r \leq \frac{a + bD}{b(1 + \varphi(1 - \nu))} \end{cases}$$

We distinguish three possibilities:

If  $\frac{a+bD}{2.b} \leq K_r$  :

By assumption,  $K_r \leq D$  and as a consequence  $\frac{a+bD}{2.b} \leq D$  which implies that  $a \leq b \cdot D$ .

In this case,  $q_R^* = \frac{a+bD}{2.b} \leq K_r$

$$\tilde{q}_r = \frac{a + bD}{b(1 + \varphi(1 - \nu))} \Rightarrow \tilde{q}_r \geq \frac{a + bD}{2.b} \text{ for } \varphi(1 - \nu) \leq 1 \text{ and } \tilde{q}_r \leq \frac{a + bD}{2.b} \text{ for } \varphi(1 - \nu) \geq 1$$

$$q_{R+T}^* = D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)}$$

As  $\leq b \cdot D$ ,  $q_{R+T}^*$  increases as  $(1 - \nu) \cdot \varphi$  increases.

Moreover, for  $\varphi(1 - \nu) = 1$ ,  $q_{R+T}^* = \frac{a+bD}{2 \cdot b}$ .

As a result,  $q_{R+T}^* \leq \frac{a+bD}{2 \cdot b}$  for  $\varphi(1 - \nu) \leq 1$  and  $q_{R+T}^* \geq \frac{a+bD}{2 \cdot b}$  for  $\varphi(1 - \nu) \geq 1$

$\Rightarrow \begin{cases} (1 - \nu) \cdot \varphi \leq 1 \Rightarrow \tilde{q}_r \geq q_R^* \geq q_{R+T}^* \\ (1 - \nu) \cdot \varphi \geq 1 \Rightarrow \tilde{q}_r \leq q_R^* \leq q_{R+T}^* \end{cases}$  and proposition 4 is proved in case  $\frac{a+bD}{2 \cdot b} \leq K_r$ .

If  $\frac{a}{b} \geq K_r$ :

Then  $a \geq K_r \cdot b$ , and by assumption  $K_r \leq D$ . As a result  $\frac{a+bD}{2 \cdot b} \geq K_r$  and  $q_R^* = K_r$ .

$\tilde{q}_r = K_r$  for  $K_r \leq \frac{a+bD}{b(1+\varphi(1-\nu))}$  and therefore at least as long as  $\varphi(1 - \nu) \leq 1$  since  $\frac{a+bD}{2 \cdot b} \geq K_r$

$$\tilde{q}_r = \frac{a + bD}{b(1 + \varphi(1 - \nu))} \quad \text{for } K_r > \frac{a + bD}{b(1 + \varphi(1 - \nu))}$$

$$q_{R+T}^* = K_r \text{ for } K_r \leq D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)}$$

If  $\frac{a}{b} \geq D$  then:

$D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)}$  decreases as  $(1 - \nu) \cdot \varphi$  increases and

$$\lim_{(1-\nu) \cdot \varphi \rightarrow +\infty} D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} = D \geq K_r$$

$\Rightarrow$  If  $\frac{a}{b} \geq D, \forall (1 - \nu) \cdot \varphi \geq 0, D + \frac{a - bD}{b \cdot ((1 - \nu) \cdot \varphi + 1)} \geq K_r$

If  $\frac{a}{b} \leq D$  then:

$D + \frac{a-bD}{b \cdot ((1-\nu) \cdot \varphi + 1)}$  increases as  $(1-\nu) \cdot \varphi$  increases and  $D + \frac{a-bD}{b \cdot ((1-\nu) \cdot \varphi + 1)} = \frac{a}{b} \geq K_r$  when  $(1-\nu) \cdot \varphi = 0$

$$\Rightarrow \text{If } \frac{a}{b} \geq D, \forall (1-\nu) \cdot \varphi \geq 0, D + \frac{a-bD}{b \cdot ((1-\nu) \cdot \varphi + 1)} \geq K_r$$

$$\Rightarrow \forall (1-\nu) \cdot \varphi \geq 0, q_{R+T}^* = K_r$$

$$\Rightarrow \begin{cases} (1-\nu) \cdot \varphi \leq 1 \Rightarrow \tilde{q}_r \geq q_R^* \geq q_{R+T}^* \\ (1-\nu) \cdot \varphi \geq 1 \Rightarrow \tilde{q}_r \leq q_R^* \leq q_{R+T}^* \end{cases} \text{ and proposition 4 is proved in case } \frac{a}{b} \geq K_r.$$

$$\text{If } \frac{a}{b} \leq K_r \leq \frac{a+bD}{2 \cdot b} :$$

From equation 10.1 we have:

$$q_R^* = K_r$$

From equation 3 we have:

$$\tilde{q}_r = K_r \text{ for } K_r \leq \frac{a+bD}{b(1+\varphi(1-\nu))} \text{ and therefore at least as long as } \varphi(1-\nu) \leq 1 \text{ since } \frac{a+bD}{2 \cdot b} \geq K_r$$

$$\tilde{q}_r = \frac{a+bD}{b(1+\varphi(1-\nu))} \text{ for } K_r > \frac{a+bD}{b(1+\varphi(1-\nu))}$$

From equation 10.2 and as  $\leq b \cdot K_r \leq b \cdot D$ ,  $q_{R+T}^*$  increases as  $(1-\nu) \cdot \varphi$  increases.

$$\text{Moreover, for } \varphi(1-\nu) = 1, D + \frac{a-bD}{b \cdot ((1-\nu) \cdot \varphi + 1)} = \frac{a+bD}{2 \cdot b} \geq K_r$$

As a result,  $q_{R+T}^* = K_r$  for  $\varphi(1-\nu) \geq 1$

$$\Rightarrow \begin{cases} (1-\nu) \cdot \varphi \leq 1 \Rightarrow \tilde{q}_r \geq q_R^* \geq q_{R+T}^* \\ (1-\nu) \cdot \varphi \geq 1 \Rightarrow \tilde{q}_r \leq q_R^* \leq q_{R+T}^* \end{cases} \text{ and proposition 4 is proved in case } \frac{a}{b} \leq K_r \leq \frac{a+bD}{2 \cdot b}.$$

Proposition 4 is therefore demonstrated in all cases.

## A.6. Proof of proposition 5.1 and 5.2

### Variation in the surplus of consumers

As demand is inelastic, the variation of the surplus of consumers in period A  $\Delta S_C^A$  when generation is curtailed to the optimal level of curtailment is equal to the variation of costs charged to consumers. Energy generated is remunerated  $p_A(K_r)$  when RES generation is not curtailed. In addition, RES generators receive a premium  $Z$ . Energy generated is remunerated  $p_A(\tilde{q}_r)$  when generation is curtailed to the optimal curtailment level, RES generators receive a premium  $Z$  when generating and compensation  $(1 - \alpha) \cdot p_A(\tilde{q}_r) + (1 - \beta) \cdot Z$  when curtailed.

The surplus of consumers in period A when generation is curtailed to the optimal level of curtailment is therefore equal to:

$$\Delta S_C^A = \int_0^{K_r} [p_A(K_r) + Z] dx + \int_{K_r}^D [p_A(K_r)] dx$$

$$- \int_0^{\tilde{q}_r} [p_A(\tilde{q}_r) + Z] dx - \int_{\tilde{q}_r}^{K_r} [(1 - \alpha) \cdot p_A(\tilde{q}_r) + (1 - \beta) \cdot Z] dx - \int_{\tilde{q}_r}^D [p_A(\tilde{q}_r)] dx$$

$$\Delta S_C^A = -D \cdot b \cdot (K_r - \tilde{q}_r) - (1 - \alpha) \cdot (K_r - \tilde{q}_r) \cdot \left[ (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} \right] + \beta \cdot Z \cdot (K_r - \tilde{q}_r)$$

In period B, the surplus of consumers is only impacted when there is no wind, with probability  $1 - \nu$ , as the price paid to thermal generators decreases when RES generation has been curtailed in period A.

$$\Delta S_C^B = (1 - \nu) \cdot \left( \int_0^D [p^{\bar{w}}(K_r)] dx - \int_0^D [p^{\bar{w}}(\tilde{q}_r)] dx \right)$$

$$\Delta S_C^B = (1 - \nu) \cdot D \cdot b \cdot \varphi \cdot (K_r - \tilde{q}_r)$$

The total variation of the consumer surplus when RES generation is curtailed from  $K_r$  to  $\tilde{q}_r$  is therefore equal to:

$$\Delta S_C = \Delta S_C^A + \Delta S_C^B$$

$$\Delta S_C = ((1 - \nu) \cdot \varphi - 1) \cdot D \cdot b \cdot (K_r - \tilde{q}_r) - (1 - \alpha) \cdot (K_r - \tilde{q}_r) \cdot \left[ (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} \right] + \beta \cdot Z \cdot (K_r - \tilde{q}_r) \quad (11.1)$$

### Variation in the surplus of thermal generators

The variation  $\Delta S_T^A$  of the surplus of thermal generators in period A when RES generation is curtailed from  $K_r$  to  $\tilde{q}_r$  is:

$$\Delta S_T^A = \int_{\tilde{q}_r}^D [p_A(\tilde{q}_r) - C_A(x - \tilde{q}_r)] dx - \int_{K_r}^D [p_A(K_r) - C_A(x - K_r)] dx$$

$$\Delta S_T^A = b \cdot (K_r - \tilde{q}_r) \cdot \left( D - \frac{\tilde{q}_r + K_r}{2} \right)$$

In period B, the surplus of thermal generators is only impacted when there is no wind, with probability  $1 - \nu$ :

$$\Delta S_T^B = (1 - \nu) \cdot \left( \int_0^D [p^{\bar{w}}(\tilde{q}_r) - C_B(x, D - \tilde{q}_r)] dx - \int_0^D [p^{\bar{w}}(K_r) - C_B(x, D - K_r)] dx \right)$$

$$\Delta S_T^B = -(1 - \nu) \cdot b \cdot \varphi \cdot (K_r - \tilde{q}_r) \cdot \left( D - \frac{\tilde{q}_r + K_r}{2} \right)$$

The total variation of the surplus of thermal generators when RES generation is curtailed from  $K_r$  to  $\tilde{q}_r$  is therefore equal to:

$$\Delta S_T = \Delta S_T^A + \Delta S_T^B$$

$$\Delta S_T = (1 - (1 - \nu) \cdot \varphi) \cdot b \cdot (K_r - \tilde{q}_r) \cdot \left( D - \frac{\tilde{q}_r + K_r}{2} \right) \quad (11.2)$$

### Variation in the surplus of RES generators

The surplus of thermal generators when RES generation is curtailed from  $K_r$  to  $\tilde{q}_r$  is only impacted in phase A.

$$\Delta S_R = \int_0^{\tilde{q}_r} [p_A(\tilde{q}_r) + Z] dx + \int_{\tilde{q}_r}^{K_r} [(1 - \alpha) \cdot p_A(\tilde{q}_r) + (1 - \beta) \cdot Z] dx$$

$$- \int_0^{K_r} [p_A(\tilde{q}_r) + Z] dx$$

$$\Delta S_R = - (K_r - \tilde{q}_r) \cdot \left[ (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} - b \cdot K_r \right]$$

$$+ (1 - \alpha) \cdot (K_r - \tilde{q}_r) \cdot \left[ (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} \right]$$
(11.3)

$$- \beta \cdot Z \cdot (K_r - \tilde{q}_r)$$

$$\Delta S_R = S_R^A(\tilde{q}_r) - S_R^A(K_r)$$

### Proof of Proposition 5.1

In the case when RES generators do not receive any compensation when curtailed, i.e.  $\beta = 1$ , then:

According to 11.1 :

$$\Delta S_C = \left( ((1 - \nu) \cdot \varphi - 1) \cdot D \cdot b + Z \right) \cdot (K_r - \tilde{q}_r)$$

And, as  $K_r \geq \tilde{q}_r$  :

$$\Delta S_C \geq 0 \Leftrightarrow (1 - \nu) \cdot \varphi \geq 1 - \frac{Z}{D \cdot b}$$

According to 11.2 :

$$\Delta S_T = (1 - (1 - \nu) \cdot \varphi) \cdot b \cdot (K_r - \tilde{q}_r) \cdot \left( D - \frac{\tilde{q}_r + K_r}{2} \right)$$

And, as  $D \geq K_r \geq \tilde{q}_r$ , therefore:

$$\Delta S_T \geq 0 \Leftrightarrow (1 - \nu) \cdot \varphi \leq 1$$

According to 11.3:

$$\Delta S_R = - (K_r - \tilde{q}_r) \cdot \left[ Z + (a + bD) \cdot \frac{\varphi(1 - \nu)}{1 + \varphi(1 - \nu)} - b \cdot K_r \right]$$

And, as  $K_r \geq \tilde{q}_r$  :

$$\Delta S_R \geq 0 \Leftrightarrow K_r \geq \frac{1}{b} \left( Z + (a + bD) \cdot \frac{\varphi(1-\nu)}{1+\varphi(1-\nu)} \right)$$

### Proof of Proposition 5.2

In the case when RES generators receive full compensation when curtailed, i.e.  $\beta = 0$ , then:

According to 11.1 :

$$\Delta S_C = (K_r - \tilde{q}_r) \cdot \left( ((1-\nu) \cdot \varphi - 1) \cdot D \cdot b - \left[ (a + bD) \cdot \frac{\varphi(1-\nu)}{1+\varphi(1-\nu)} \right] \right)$$

And, as  $K_r \geq \tilde{q}_r$  :

$$\Delta S_C \geq 0 \Leftrightarrow ((1-\nu) \cdot \varphi - 1) \cdot D \cdot b - \left[ (a + bD) \cdot \frac{\varphi(1-\nu)}{1+\varphi(1-\nu)} \right] \geq 0$$

$$\Delta S_C \geq 0 \Leftrightarrow ((1-\nu) \cdot \varphi)^2 - \frac{a + b \cdot D}{b \cdot D} \cdot ((1-\nu) \cdot \varphi) - 1 \geq 0$$

This quadratic equation admits only one positive root, and:

$$\Delta S_C \geq 0 \Leftrightarrow (1-\nu) \cdot \varphi \geq \frac{1}{2} \times \left[ \frac{a + b \cdot D}{b \cdot D} + \sqrt{\left( \frac{a + b \cdot D}{b \cdot D} \right)^2 + 4} \right]$$

According to 11.2 :

$$\Delta S_T = (1 - (1-\nu) \cdot \varphi) \cdot b \cdot (K_r - \tilde{q}_r) \cdot \left( D - \frac{\tilde{q}_r + K_r}{2} \right)$$

And, as  $D \geq K_r \geq \tilde{q}_r$ , therefore:

$$\Delta S_T \geq 0 \Leftrightarrow (1-\nu) \cdot \varphi \leq 1$$

According to 11.3:

$$\Delta S_R = (K_r - \tilde{q}_r) \cdot b \cdot K_r$$

And, as  $K_r \geq \tilde{q}_r$  :

$$\Delta S_R \geq 0$$

### A.7. Proof of proposition 6

For two level of curtailment resulting in RES generation  $\tilde{q}_r$  and  $\hat{q}_r$  the variation of the social welfare is equal to:

$$S(\tilde{q}_r) - S(\hat{q}_r) = C(\hat{q}_r) - C(\tilde{q}_r) = \int_{\tilde{q}_r}^{\hat{q}_r} \frac{dC(q_r)}{dq_r} dq_r$$

From equation (2) :

$$S(\tilde{q}_r) - S(\hat{q}_r) = (a + b.D).(\tilde{q}_r - \hat{q}_r) + \frac{1 + \varphi.(1 - \nu)}{2}.b.(\hat{q}_r^2 - \tilde{q}_r^2) \quad (12.1)$$

Similarly, the variation of the surplus of RES generators is equal to:

$$S_R(\tilde{q}_r) - S_R(\hat{q}_r) = \int_{\tilde{q}_r}^{\hat{q}_r} \frac{dS_R(q_r)}{dq_r} dq_r$$

According to equation (6.1) , and in case RES do not receive any compensation (i.e.  $\alpha = \beta = 1$ ):

$$S_R(\tilde{q}_r) - S_R(\hat{q}_r) = (Z + (a + b.D)).(\tilde{q}_r - \hat{q}_r) + b.(\hat{q}_r^2 - \tilde{q}_r^2) \quad (12.2)$$

We then define  $\tilde{q}_r$  as the optimal production level in period A corresponding to a variability equal to  $(1 - \nu)$  and  $\hat{q}_r$  as the optimal production level in period A corresponding to a variability equal to  $(1 - \hat{\nu})$ .

According to equation (3):

$$\tilde{q}_r = \frac{a + bD}{b.(1 + \varphi(1 - \nu))} \quad \text{for } K_r > \frac{a + bD}{b.(1 + \varphi(1 - \nu))}$$

$$\hat{q}_r = \frac{a + bD}{b.(1 + \varphi(1 - \hat{\nu}))} \quad \text{for } K_r > \frac{a + bD}{b.(1 + \varphi(1 - \hat{\nu}))}$$

We also assume that there is a rational for curtailment in both cases:

$$K_r > \frac{a+bD}{b.(1+\varphi(1-\nu))} \text{ and } K_r > \frac{a+bD}{b.(1+\varphi(1-\hat{\nu}))}$$

According to equation (12.1):

$$S(\tilde{q}_r) - S(\hat{q}_r) = (a + b.D).(\tilde{q}_r - \hat{q}_r) + \frac{1 + \varphi.(1 - \nu)}{2}.b.(\hat{q}_r^2 - \tilde{q}_r^2)$$

$$S(\tilde{q}_r) - S(\hat{q}_r) = \frac{(a + b.D)^2}{2.b} \cdot \frac{\varphi^2.(v - \hat{v})^2}{(1 + \varphi(1 - \nu)).(1 + \varphi(1 - \hat{\nu}))^2}$$

$$\text{For } \nu - \hat{\nu} \ll \nu \text{ then } S(\tilde{q}_r) - S(\hat{q}_r) \approx \frac{(a+b.D)^2}{2.b} \cdot \frac{\varphi^2.(v-\hat{v})^2}{(1+\varphi(1-\nu))^3} \quad (13.1)$$

Similarly, according to equation (12.2):

$$S_R(\tilde{q}_r) - S_R(\hat{q}_r) = (Z + (a + b.D)).(\tilde{q}_r - \hat{q}_r) + b.(\hat{q}_r^2 - \tilde{q}_r^2)$$

$$\text{For } \nu - \hat{\nu} \ll \nu \text{ then } \quad (13.2)$$

$$S(\tilde{q}_r) - S(\hat{q}_r) \approx \frac{(a+b.D)}{b} \cdot \frac{\varphi.(v-\hat{v})}{(1+(1-\nu).\varphi)^2} \cdot \left( Z + (a + b.D) \cdot \frac{(\varphi.(1-\nu)-1)}{1+\varphi.(1-\nu)} \right)$$

And in particular, for  $Z = 0$ :

$$S(\tilde{q}_r) - S(\hat{q}_r) \approx \frac{(a + b.D)^2}{b} \cdot \frac{\varphi.(v - \hat{v})}{(1 + (1 - \nu).\varphi)^3} \cdot (\varphi.(1 - \nu) - 1) \quad (13.3)$$

# Chapter 4

## FINANCING INVESTMENT IN THE EUROPEAN ELECTRICITY TRANSMISSION NETWORK: CONSEQUENCES ON LONG- TERM SUSTAINABILITY OF THE FINANCIAL STRUCTURE OF TSOS

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### 6 INTRODUCTION

The development of the European electricity transmission grid plays a key role in the European Union's strategy to address challenges such as decarbonisation of the generation mix, security of supply and market integration. However it remains unclear whether regulated Transmission System Operators (TSOs) will be able to cope with the substantial amount of investment required which is unprecedented since liberalisation.

Previous studies (such as Roland Berger (2011)) have considered the issue of investment by focusing on the volumes of spending over one or two decades. The main question they address is whether sufficient amounts of debt and equity will be available; they do not consider the resulting yearly constraints on the parameters observed by investors to assess the financial health of a company. Other studies focus on the definition of an adequate regulatory framework and the required incentives to ensure that investment is carried out by TSOs (a good review of the related issues can be found in Guthrie, G. (2006)).

Our approach differed as we focused on identifying an appropriate financing strategy for TSOs to meet the need for capital expenditure. In comparison to the studies previously

mentioned, we took as a starting point the assumption that an adequate regulatory framework would be in place and that the corresponding volume of debt would be accessible on financial markets at a reasonable cost. We then compared a set of financing options by measuring the costs for network users to deliver a certain volume of investment, while conserving good financial ratings (corresponding to an investment-grade for rating agencies).

We based our study on a set of investment needs identified in previous studies by the European Commission and the European TSOs, and we focused on the resulting annual financial constraints for TSOs in the ENTSO-E area over the period 2012-2030. We based our analysis on some of the insights delivered by Neuhoff, K., R. Boyd and J.-M. Glachant (2012); grid investment will be mostly financed against revenues from tariffs charged to users, and TSOs cannot finance the full scale of investment by simply raising debt. If TSOs are to find money on capital markets, they must adhere to some constraints on a set of financial ratios. We assessed quantitatively these challenges, estimated the financing gap for a set of investment scenarios, and studied the potential of alternative financing strategies to fill this gap at a lower cost for consumers.

We did not look at local restrictions in order to allow us to focus on the challenges faced by a virtually integrated European electricity transmission industry. In order to simplify the results, and due to the increasingly close relationship between the different European TSOs, we made the assumption that a single virtual TSO would be responsible for the whole transmission network in the ENTSO-E area. Our framework is therefore a best-case scenario in which some constraints specific to a given TSO are disregarded.

Our results show that in their current financial situation, and considering historical trends in transmission tariffs, TSOs will not be able to achieve more than half of the investment plans. Higher capital expenditure would result in financial degradation of TSOs and a rapid loss of their investment grade. Tariffs will have to increase significantly should all of investment plans be met. Alternative financing strategies could lower costs for consumers, but only to a minor extent.

## 7 GENERAL FRAMEWORK OF THE STUDY

### 7.1 Challenging wave of spending in the European electricity transmission grid

The European electricity transmission grid is facing pressing needs for new transmission lines, mostly in order to incorporate renewables<sup>1</sup> and new conventional plants, but also to address security of supply and ensure market integration. In addition, a major share of the existing network is to be renovated in the coming decades (IEA 2011). As a result, European TSOs will be exposed to uninterrupted and substantial capital expenditure over the two next decades.

The ten-year plan established in 2012 by the European Network of Transmission System Operators for electricity (ENTSO-E) identified costs of €104 billion to be spent in the next ten years on projects of pan-European significance alone. Even with plans by European TSOs to raise spending by approximately 70% compared to the period 2005-2009, there would still be a significant gap to be met (Roland Berger 2011).

### 7.2 Ability of the TSOs to finance investment

#### *Definition of financeability*

The lifetime of transmission assets is on average 40 years, but can be much longer in some cases. As a consequence, high upfront costs must be covered when the investment is made while pay-back is delivered through a low return over a long period. Even in cases when profitability in the long-term is ensured, TSOs still need initially to raise capital.

Financeability hereby refers to the ability of TSOs to raise finance from capital markets in order to meet their investment programme. We consider that in order to achieve their objectives, it is necessary for TSOs to conserve good financial ratios, corresponding to an investment grade status for rating agencies. In addition, financeability implies that the return on the regulatory asset base is sufficient to cover the costs of capital of investors.

#### *Sources of financing*

There are three basic ways in which TSOs can finance capital expenditures: investors can raise debt (loans from commercial banks or institutions, corporate bonds); they can fund investment internally by retaining earnings; or they can find external sources of equity.

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<sup>1</sup> According to the ENTSO-E, 80% of the bottlenecks that are to appear in the European transmission grid by the end of the decade are related to RES-integration.

Since liberalisation, debt issuance has been the option most commonly employed by integrated utilities in general and European TSOs in particular (IHS CERA 2013). As a result, the volume of debt has continued to rise (the leverage of European electricity TSOs is typically about 60-70% today), which limits the ability of these companies to acquire further debt without losing their credit rating.

Internal equity is a major source of financing for some small European TSOs, but it alone is not sufficient when investment needs increase significantly. Moreover, investors in TSOs traditionally expect a high dividend pay-out ratio, which limits the ability of TSOs to finance investment internally. An empirical study published by the National Grid (2012) revealed that utilities continue to pay a substantial dividend (at least 50% of profits) even when they need to raise equity.

Raising external equity is an attractive option when the level of debt has to be kept below a certain threshold. Yet it is also a more expensive option. In comparison to bond holders, the returns for equity investors vary with the profits and losses of the company; they therefore require a higher return to compensate for this equity risk. In addition to higher costs, there are two main obstacles to financing investment, due to the fact that most European TSOs are still publicly owned<sup>2</sup> (Roland Berger 2011). Cash-strapped European States are not able to inject liquidity; as pointed out by Helm, D. (2009), States facing budgetary constraints prefer to protect operational expenditures (OPEX) and reduce capital expenditures (CAPEX). States might also be reluctant to dilute their ownership share of crucial assets with major public goods properties.

### ***Financing strategies***

Each of the three possible sources of financing is therefore associated with specific limitations, costs and constraints. In this chapter we study the potential of a set of financing strategies to fill the investment gap, while also conserving good financial ratios. The definition of these strategies is based on Neuhoff, K., R. Boyd and J.-M. Glachant (2012).

Under the ‘business-as-usual strategy’ (BAU) scenario, capital expenditure is financed by debt and a minor share of the earnings that have not been distributed as dividends.

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<sup>2</sup> Even in situations of private ownership (as in Belgium, Italy and Spain), public entities still hold a large minority share.

In the ‘issue additional equity’ scenario, the high dividend pay-out ratio is maintained but the TSOs issue additional equity (instead of debt) to finance capital expenditure.

In the ‘shift to growth model’ scenario, the dividend pay-out ratio is lowered and TSOs retain earnings in order to finance capital expenditure internally. Shareholders do not receive their return as cash but from holding the share for a while and selling it at a higher value at a later date.

## **8 ASSUMPTIONS BEHIND CALCULATIONS**

We calculated the impact on the balance sheet of a virtual unified European TSO, using as inputs the initial situation in 2012 and a set of assumptions regarding annual expenditure until 2030. We were then able to extrapolate the evolution of the financial ratios of the TSO and the impact on tariffs for the consumer.

### **8.1 Defining a virtual single European TSO**

In order to simplify the results, we made the assumption that the different European (i.e. members of ENTSO-E) TSOs could be virtually aggregated into a single European TSO, in charge of the whole volume of investment.

One could argue that the TSOs aggregated into our single company differ widely in terms of size, investment plans, ownership and financial situation. However we consider our assumption to be valid, as a first approximation.

The rationale behind our hypothesis is two-fold. Firstly, similar key sources of financing will be accessible to most European TSOs. Public funds are often allocated at a supranational level, such as the European Investment Bank, the European Bank for Reconstruction and Development, the European Energy Programme for Recovery and the Energy Infrastructure Package. Banks and potential investors also rarely restrict the geographical scope of their investments to a single country<sup>3</sup>. In addition, TSOs remain relatively low-risk business in all the countries that are part of the ENTSO-E. As long as these TSOs remain in the “investment grade” range, which was still the case for all of them in 2011 (Roland Berger 2011) investors are not likely to treat them differently one from the other. It is also likely that as a result of European integration, the remaining

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<sup>3</sup> A recent example of cross-border investments is the buy-out of 40% of Portugal’s national power grid *Redes Energéticas Nacioanais* by China’s State Grid Corporation and Oman Oil.

differences will increasingly disappear by 2030 (see Ruester, S., C. Marcantonini, X. He, J. Egerer, C. VON HIRSCHHAUSEN and J.-M. GLACHANT (2012) for a discussion of these issues).

Secondly, cross-border industry consolidation and mergers between TSOs is not unrealistic, as proven by investments made by TenneT and Elia in Germany. Smaller TSOs facing significant investment needs could cooperate with larger TSOs which have easier access to financing.

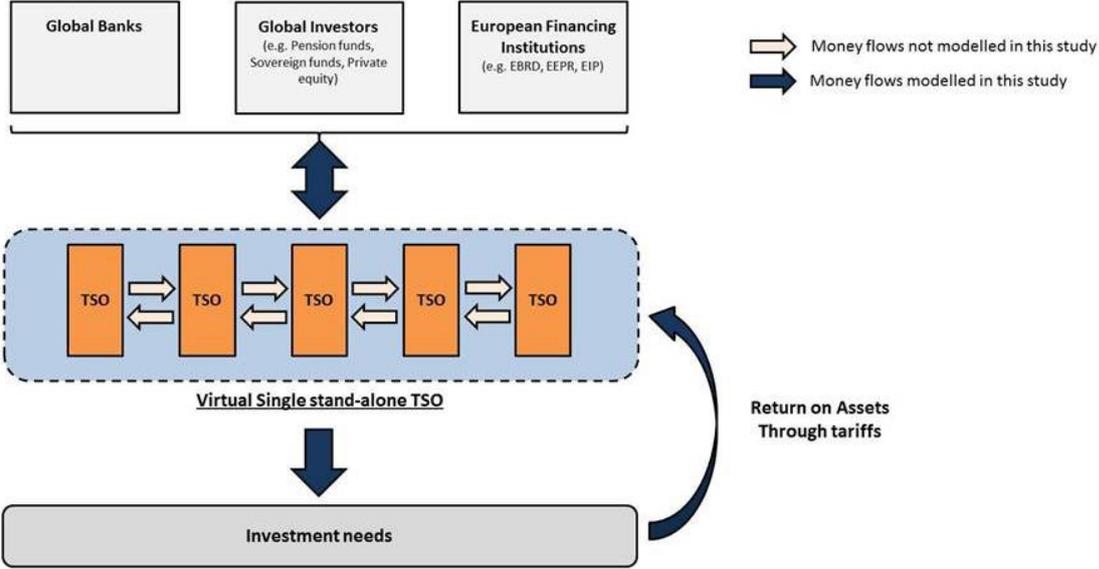


Figure 15: Illustration of the assumption of a single European TSO

As a result, we considered that the required funds could flow from one pool of financing sources, and then be distributed between a set of communicating vessels to fulfil a common set of investment needs (See Figure 15).

Note that smaller TSOs facing significant investment needs and ownership restrictions might be exposed to more challenging local constraints that would not appear in this study. Our primary focus was to identify constraints at the level of the European transmission grid industry: our study can be considered as a best-case scenario for which full integration (or at least full cooperation) of the European TSOs would be achieved.

## 8.2 Investment programmes

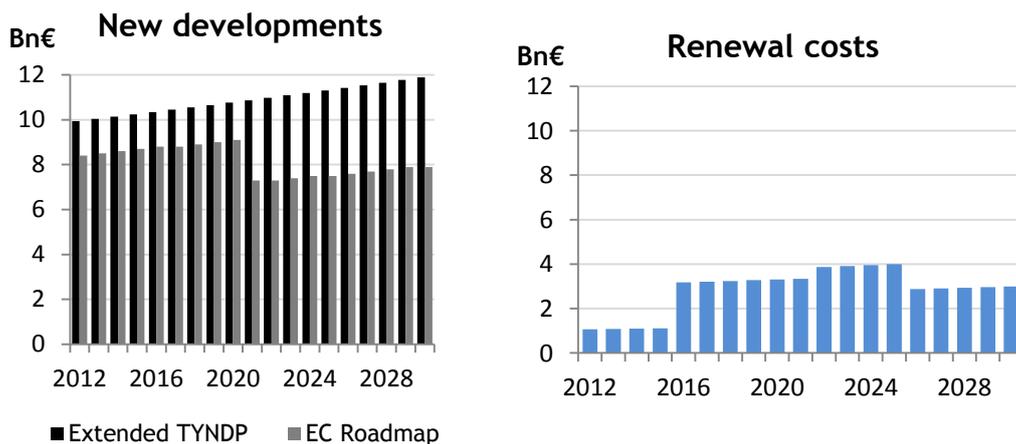


Figure 16: Annual investment costs in the ENTSO-E area over the period 2012-2030 (€2012 Billion)

In this study, the volume of investment is exogenously determined and is independent from the financing strategy. We identified two main categories of transmission costs: grid expansion required to accommodate both demand growth and the deployment of renewables; and the refurbishment and replacement of existing assets. The resulting spending profiles are represented in Figure 16.

### *New developments*

We employed two possible scenarios for investment in new projects.

The first scenario for transmission investment (hereby referred to as ‘Extended TYNDP’) was based on the TYNDP 2012, involving 52,300 km of new circuits for a total cost of €104 billion over the period 2012-2021. As the period we considered extends up to 2030, we made the assumption that development would remain similar until 2030. The total investment needs identified over the period 2012-2030 were therefore estimated to be close to € 207 billion.

To obtain a yearly investment profile for our stand-alone TSO, we considered the spending to be constant (in terms of length of circuits built) within each period. The annual investments were then adjusted for the sector-specific inflation<sup>4</sup>.

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<sup>4</sup> Our calculations were realised using real values. However the inflation specific to investments realised by the TSOs might differ from the more general Consumer Price Index. Based on historical

The second scenario (hereby referred to as ‘EC Roadmap’) was based on the Impact Assessment of the Energy Roadmap 2050 (European Commission 2011). Under the Current Policy Initiative scenario, we deduced that TSOs in the ENTSO-E area would face investment needs equal to € 79 billion over the time period 2012-2020, and investment needs equal to € 76 billion over the time-period 2021-2030. As in the previous scenario, the annual investment was considered to be constant in terms of km of circuits within each period. We also considered that the costs per km of new circuits were similar to the ones of the TYNDP.

### ***Renewal of ageing networks***

To these two scenarios for new projects, we added a single complementary scenario for renewal costs of the existing network. In order to establish the needs for infrastructure renewals, we used the analysis developed in the IEA World Energy Outlook 2011.

The IEA states that assets should be replaced on reaching 40 years of age on average. For OECD Europe, the IEA estimated that 8% of the existing networks need to be replaced by 2015, 21% between 2016 and 2025, and 15% between 2026 and 2035. According to the IEA, this would result in total costs of \$2010 82 billion for the European Union over the period 2011-2035. This figure scales up to a total cost of €2012 76 billion for the ENTSO-E area<sup>5</sup>. Once again, we considered investment to be constant (in terms of length of circuits built) within each of these three periods.

Finally, according to the TYNDP 2012 edited by ENTSO-E, 8,300 km of refurbishment could be avoided between 2012 and 2021 due to investment in new assets. We considered the renewals investments would therefore be reduced by a corresponding constant annual amount throughout this period.

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data from France, we obtained an average annual additional inflation of 1.13%. This result was obtained by comparing the TP12 index for construction works in “Electricity networks” (*Réseaux d’électrification*) to the harmonised consumer price index over the period 1996-2012.

<sup>5</sup> The resulting cost per km of these refurbishment investments is relatively smaller than the one for new investments. However this can be explained as a significant part of the costs can be avoided in case of refurbishment.

Note that while the volume of investment required for infrastructure renewal is not as important as the one related to new investment (See Figure 16), it is still too important to be disregarded.

### **8.3 Calculating tariffs and the TSO revenues**

The revenues of European TSOs are determined by the regulatory framework. In this analysis, the regulatory scheme considered to be in place is a simple ‘cost-plus’ mechanism; costs are directly passed on to consumers, and there are no incentives in place to reduce these costs. While the majority of regulatory schemes in Europe feature different performance incentives, any scheme should at least aim to cover costs and provide a satisfactory return on capital. In the absence of significant efficiency gains, our assumption of a fixed return seems reasonable.

As a result, tariffs in our model are designed to cover depreciation costs, network losses (proportional to consumption) as well as network-related OPEX (proportional to network length), and to provide a return on the regulated asset base. Costs related to the provision of system services are excluded from our analysis. Further details can be found in the appendix.

### **8.4 Establishing financeability standards**

In order to assess the quality of the financial ratios of the single TSO, we used the methodology employed by the rating agency Moody’s to establish the rating of companies developing regulated electric and gas networks (Moody’s 2009).

For more clarity, we focused on the two main quantitative credit metrics taken into consideration by Moody’s. Each of them account for 15% of the overall rating, and about 40% of the quantitative part of the rating. The adjusted Interest-Cover Ratio is calculated as Earnings before Interest and Taxes (EBIT) divided by interest payments. It reflects the flexibility of the regulated TSOs to pay interests on their debts. The Gearing Level is calculated as the volume of debt divided by the total value of the Regulated Asset Base: it represents the loan to value ratio. More details can be found in the methodology published by Moody’s (2009).

From a sample of TSOs’ financial ratings, we defined two standards in line with typical TSO profiles. In order to reach the higher standard, a TSO must achieve a rating of Aa for adjusted Interest Cover Ratio, and a rating of A for gearing (as was the case for REE and Terna in 2009). In order to reach the lower standard, a TSO must achieve in our study a rating of A for adjusted Interest Cover Ratio, and a rating of Baa for gearing (this was the

case of REN and Statnett in 2009). The corresponding values can be found in Table 3. Note that both standards correspond to an investment-grade status.

	Adjusted Interest cover Ratio		Gearing	
	Rating	Value	Rating	Value
Higher standard	Aa	$\geq 4$	A	$\leq 60\%$
Lower Standard	A	$\geq 2$	Baa	$\leq 75\%$

Table 3: Threshold value for financial ratings by Moody’s

In both cases, in order to achieve a given rating, the three-year average value of an indicator must remain on top of the corresponding threshold value. It is therefore possible to be below the threshold for any given year, which is also the methodology employed by Moody’s.

## 9 RESULTS

### 9.1 Results in the business-as-usual scenario

#### *Definition of the business-as-usual scenario*

The financing strategy applied in our business-as-usual (BAU) scenario was established after discussion with industry members and was designed to reflect current trends.

In this scenario, there is no injection of external equity into the TSO, and the pay-out ratio is equal to 70%.

#### *Financing gap under current trend in tariffs*

With this scenario, the annual rise in tariffs is limited to the trend observed for consumption-weighted average rise in electricity transmission tariffs seen in the ENTSO-E area between 2009 and 2011. Using the transmission tariffs reports published by ENTSO-E, this maximum rise in tariffs was estimated to be equal to 1.04% in real terms.

Tariffs in the first year (i.e. 2012) were estimated using the transmission tariffs report of ENTSO-E. They correspond to a nominal pre-tax rate-of-return on assets equal to 7.5%

With a financing strategy based on debt issuance, and with a limited rise in tariffs, both investment scenarios led to a severe degradation of the TSO financial status. The constraints related to new investment are such that the TSO financial ratios would correspond to a speculative grade in 2019 for the Extended TYNDP scenario and in 2021 for the EC Roadmap scenario. The financial situation of the TSO would continue to worsen until the end of the decade (2030).

If an investment grade were to be maintained, it would only be possible for the TSO to develop 47% of the new investment planned in the TYNDP scenario, and 61% of the EC Roadmap scenario.

Note that in any case, it would be impossible with such a financing strategy to achieve the higher standard defined in section 8.4. This is due to the fact that the initial gearing level is already close to the limit of this higher standard. Without further equity, either internal or external, it is then impossible to keep the debt level above the higher threshold.

	Scenario	
	Extended TYNDP	EC Roadmap
Share of investments achievable	47%	61%
Average nominal pre-tax ROA	6.1%	6.0%
Average nominal post-tax ROE	7.2%	7.1%
Amount of new debt required by 2030 (Billion Euro)	41	37

Table 4: Share of investment programmes achievable under current trends in tariffs

***Evolution of tariffs required to achieve the whole investment program***

In our BAU scenario, there is no injection of external equity. In order to keep the debt level below a 75% threshold (the limit of our lower standard), the amount of earnings retained by the TSO must be high enough to cover equity needs. As the dividend pay-out ratio is also kept constant in this BAU case, a raise in transmission tariffs would then be mechanically required to increase retained earnings.

We estimated that the tariffs increases<sup>6</sup> required to ensure the financeability of 100% of our first investment scenario (extended TYNDP) would be equal to an annual rate of CPI+3.4%, roughly three times the trend observed in the past years. As the dividend pay-out ratio is kept constant, such an increase in tariffs would result in a significantly higher return on equity (ROE) equal to 12.0% (nominal post-tax). Similarly, ensuring financeability of our second investment scenario (EC Roadmap) would require an annual increase in tariffs equal to CPI+2.1% and it would result in a ROE equal to 8.2% (nominal post-tax).

A detailed breakdown of the rise in tariffs between 2012 and 2030 is provided in Figure 17. Note that the two most important sources of increase are depreciation and interest payments, with the rise of dividends only accounting for a minor share of the total increase.

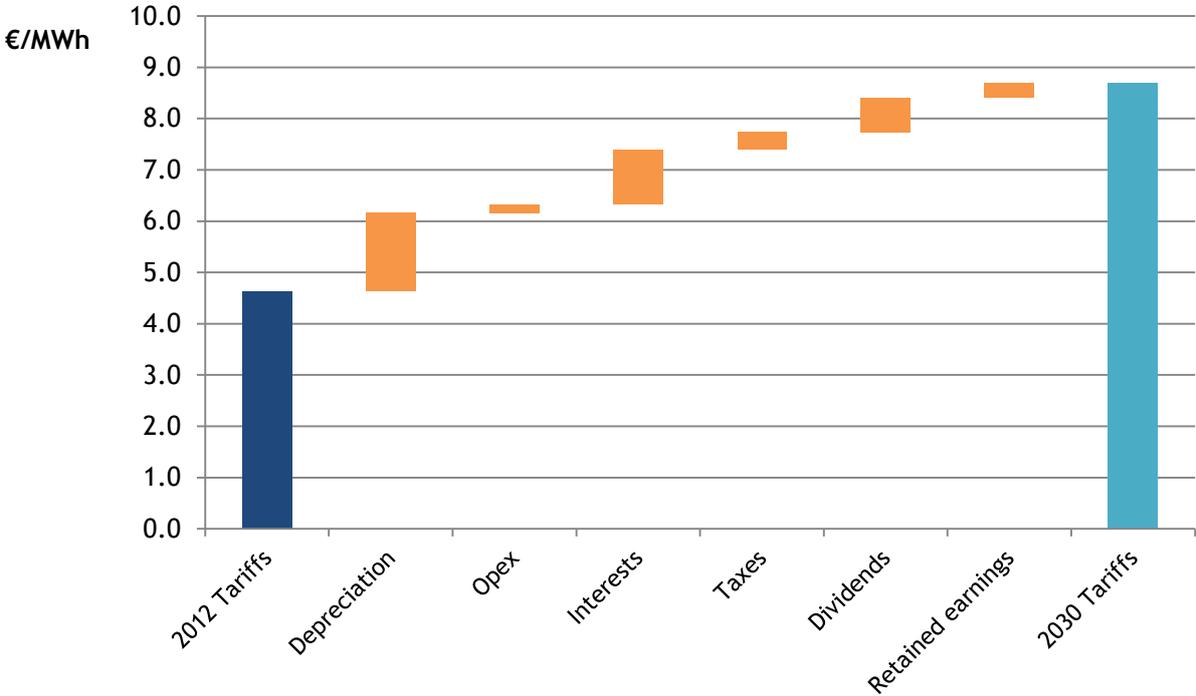


Figure 17: Components of the increase in tariffs required between 2012 and 2030 in order to achieve 100% of the Extended TYNDP investment programme

<sup>6</sup> Note that as explained in section 8.3, costs related to the provision of system services are not taken into consideration in this study.

## 9.2 Results for alternative financing strategies: issue additional equity

In the BAU financing strategy, a significant increase in tariffs will be required in order to cover substantial capital expenditures while keeping debt at a relatively low level. By injecting external equity, it could be possible to conserve the lower standard we defined, at a lower cost for consumers. However, as equity is more costly than debt, a trade-off has to be found between releasing the constraints on financial ratios by injecting equity, and funding spending with cheap debt rather than equity.

### *Financing gap under current trend in tariffs*

		Equity injection as a share of Total financing needs			
		0%	15%	30%	50%
Extended TYNDP	Share of investments achievable	47%	50%	54%	61%
	Equity injected by 2030 (Billion €)	0	7	16	32
	Average nominal post-tax ROE	7.2%	6.6%	5.9%	5.0%
EC Roadmap	Share of investments achievable	61%	66%	71%	81%
	Equity injected by 2030 (Billion €)	0	7	15	31
	Average nominal post-tax ROE	7.1%	6.3%	5.7%	4.7%

Table 5: Share of investments achievable in the ‘Issue additional equity’ scenario

By injecting equity, it will be possible to finance a larger proportion of investment programmes while conserving the investment-grade. Yet, as the costs of interest on debt are fixed and lower than the costs of equity, injecting further equity while maintaining tariffs at the same level will result mechanically in reducing the ROE (See Table 6). This would downgrade the attractiveness of investing in the company. The extent to which external sources of equity could be found to finance large-scale investments without increasing tariffs is therefore limited.

### *Evolution of tariffs required to achieve the whole investment program*

By injecting a small share of external equity, it is possible to achieve the full scale of the investment programme while reducing any impact on tariffs. However, higher amounts of equity lead to further expenses in order to provide a satisfactory return to investors.

The optimum is found for relatively small level of equity injections, as illustrated in Figure 18. In order to achieve a 8% post-tax nominal ROE, the minimum annual increase in tariffs is obtained for equity injections equal to 8% of financing needs, which amount to € 10 billion over the time period 2012-2030. In order to achieve a 10% post-tax nominal ROE, the minimum annual increase in tariffs is obtained for equity injections equal to 4% of financing needs, which amount to € 5 billion over the time period 2012-2030.

Note that in any case, a significant rise in tariffs would still be required to achieve the whole scale of the investment programs.

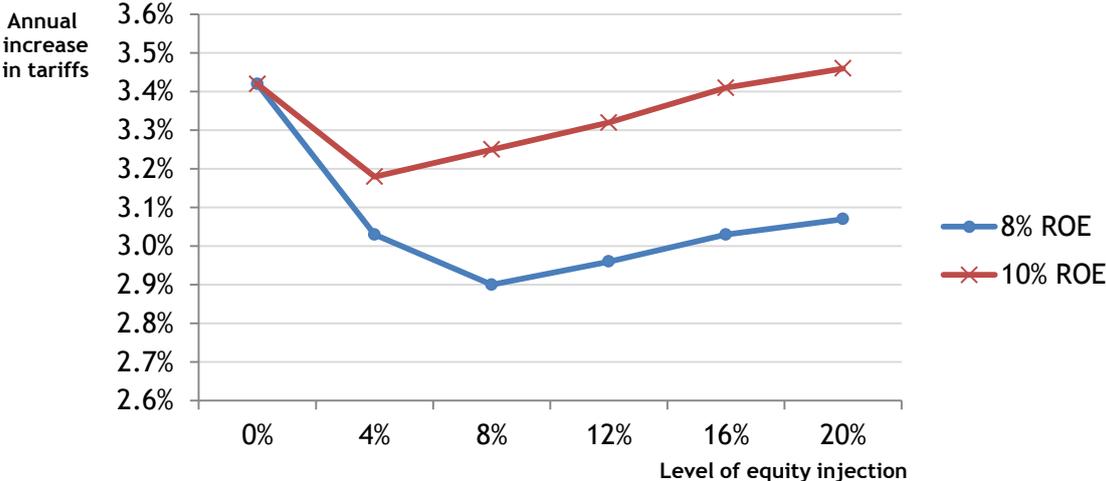


Figure 18: Average annual increase in tariffs required to achieve a given average ROE while conserving investment grade for different levels of equity injection in the ‘Extended TYNDP’ scenario

**9.3 Results for alternative financing strategies: shift to growth model**

Rather than finding sources of external equity, the TSO could fund spending internally by lowering the dividend pay-out ratio. Note that this would require a change in perception of investors, as TSOs are typically considered as a low-risk investment with a high pay-out ratio.

***Financing gap under current trend in tariffs***

By retaining earnings, it would be possible to achieve a slightly higher share of the investment programme for the same level of tariffs (See Table 6). However, for the same level of tariffs, as in the ‘Issue additional equity’ scenario, retaining earnings automatically leads to a reduced ROE. In addition, there is also a shift in the nature of the return, as a more significant part of this return is received from holding the share and

selling it back at a later date instead of receiving a cash dividend. As mentioned in section 7.2, this change might not be accepted easily by investors, who could then demand a higher ROE. However in this study we disregarded such an effect: our results once again constitute a best-case scenario regarding the evolution of transmission tariffs.

		Dividend Pay-out ratio		
		70%	50%	30%
<b>Extended TYNDP</b>	Share of investments achievable	47%	51%	54%
	Average nominal post-tax ROE	7.2%	6.4%	5.8%
	ROE received as dividends	5.0%	3.2%	1.7%
<b>EC Roadmap</b>	Share of investments achievable	61%	66%	71%
	Average nominal post-tax ROE	7.1%	6.3%	5.6%
	ROE received as dividends	5.0%	3.1%	1.7%

Table 6: Share of investments achievable in the ‘shift to growth model’ scenario

***Evolution of tariffs required to achieve the whole programme of investments***

By retaining part of the earnings, it is possible to achieve the full scale of investment while limiting an increase in transmission tariffs. As in the previous financing strategy, an optimum has to be found between releasing constraints on financial ratios and paying a higher return on a higher share of equity.

In order to achieve a ROE equal to 8%, the optimum is found for a dividend pay-out ratio equal to 55%. In order to achieve a ROE equal to 10%, the optimum is found for a dividend pay-out ratio equal to 65%. Lower pay-outs lead to an expensive and unnecessarily high use of internal equity financing, while higher pay-outs make higher tariffs necessary to bypass constraints on financial ratios. In any case, the required increase in tariffs will remain relatively high.

Note that while both optimal pay-out ratios are still relatively high, lower dividend pay-out ratio will also result in a lower share of this return being provided under the form of cash dividends, which might not be without consequences on attractiveness to investors.

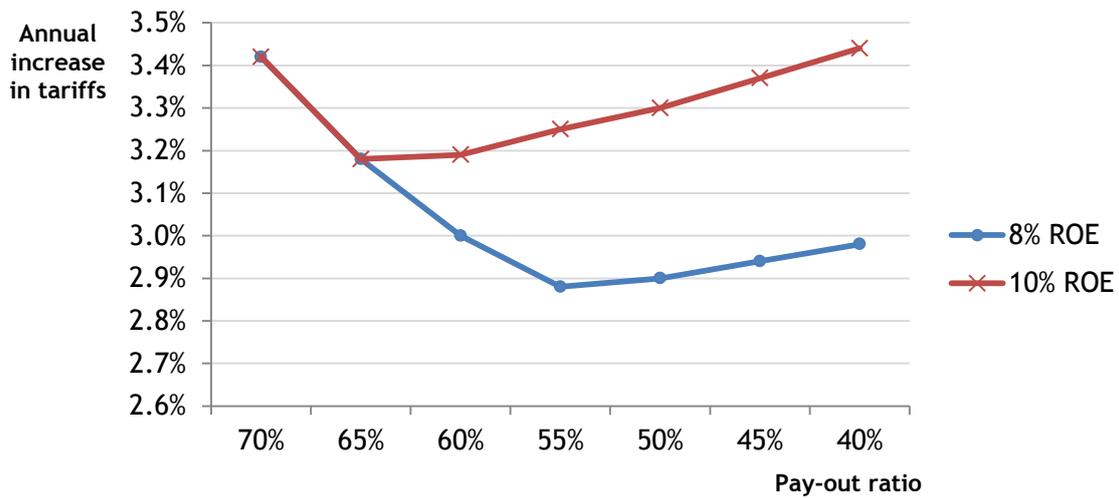


Figure 19: Average annual increase in tariffs required to achieve a given average ROE while conserving investment grade for different levels of dividend pay-out ratio in the ‘Extended TYNDP’ scenario

#### 9.4 Policy implications of these results

As explained in the introduction, in this chapter we looked at the issue of financeability of investment in the transmission network using a different approach than existing studies. More traditional issues include identifying and allocating costs and benefits, delivering adequate incentives to TSOs, and getting access to debt at reasonable costs<sup>7</sup>. Our analysis revealed that in addition to these, even if all these challenges were solved, there could still be limits to TSOs’ abilities to meet the need for investment.

Financing uniquely through debt could lead to a threat that the volume of the debt might become too significant for TSOs to meet repayment obligations. This situation is reflected

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<sup>7</sup> A recent discussion on the issues related to Cost-Benefit analysis of transmission projects can be found in MEEUS, L., N.-H. VON DER FEHR, I. AZEVEDO, X. HE, L. OLMOS, and J.-M. GLACHANT (2013): "Cost Benefit Analysis in the Context of the Energy Infrastructure Package."

The topic of incentives for TSOs is for instance dealt with in GLACHANT, J.-M., H. KHALFALLAH, Y. PEREZ, V. RIOUS, and M. SAGUAN (2012): "Implementing Incentive Regulation and Regulatory Alignment with Resource Bounded Regulators."

in the degradation of key financial metrics. It means that TSOs' ability to meet their obligations would then be vulnerable to small perturbations of the allowed rate-of-return. Financing institutions will only accept such a situation if the regulatory framework is very stable and if returns are guaranteed in the long-term. Rules put into place should in particular minimise the eventuality of a regulatory hold-up.

According to our results, the business-as-usual financing strategy of TSO would not be the most adequate strategy to finance a significant wave of investment. Significant savings could be achieved by resorting to alternative financing strategies. The implementation of these strategies would require a change of the perception of TSOs owners (mainly public entities), for instance opening TSOs to external sources of equity, and to new kind of investors attracted by growth entities.

In any case, an increase in investment will lead to a significant increase in costs, mostly to cover depreciation and interest payments. Transmission tariffs only constitute a small share of the total costs of electricity for consumers, but a three-fold increase of their annual growth might nevertheless generate protests. It is important not to sacrifice significant benefits in the long-term to limit spending in the short-term. Similarly, it is essential to ensure that the need for significant sources of financing is perceived as being associated to real needs and not as a result of bad management.

## **10 CONCLUSION**

In this chapter, we focused on assessing the ability of European TSOs to finance the substantial capital expenditure forecasted by 2030. As a first approximation, we only considered a first level of constraints at the scale of a virtually unified European transmission network operator. However, even in this 'best-case' scenario, we were still able to identify limits to the volume of investment achievable.

Under current trends in the evolution of transmission tariffs, the investment programmes established in the EC roadmap and the TYNDP published by ENTSO-E will be unsustainable in the long-term. To avoid severe degradation of the TSOs financial profile, a significant increase in tariffs would be required.

Alternative financing strategies, such as issuing additional equity or restraining dividends, could help to achieve the whole scale investment volumes at a lower cost to consumers.

However, these financing strategies cannot fully substitute an increase in tariffs. A very radical shift would only allow a slightly higher share of the investment plans to be

financed, at the expense of a decrease of the ROE. Injecting capital into the transmission business would not remain attractive under such conditions.

Note that in this analysis, the cost of debt and capital are considered to be independent from the financing structure. Further constraints could appear when taking their interaction into account.

## **ACKNOWLEDGEMENTS**

The author would like to thank Jerome Dejaegher, Jean-Michel Glachant and participants to the 2013 Executive Seminar of the Florence School of Regulation for the precious comments received.

## APPENDICES

### A.1 Details of the calculations

Variable	Description	Unit
$RAB(t)$	Regulated Asset Base at time $t$	M€
$Inv(t)$	Investments in new projects at time $t$	M€
$RenewInv(t)$	Renewal investments at time $t$	M€
$Dep(t)$	Depreciation at time $t$	M€
$AverageRAB(t)$	Average Regulated Asset Base at time $t$	M€
$T$	Accountable life expectancy of new assets	Years
$T_0$	Accountable life expectancy of existing assets	Years
$g(t)$	Network growth factor at time $t$	M€ / km
$Network\_Length(t)$	Network Length at time $t$	km
$Opex\_Network(t)$	Network-related OPEX at time $t$	M€
$UC\_OPEX$	Network-related OPEX costs per km	M€/km
$Cons(t)$	Energy consumption at time $t$	TWh
$Cons\_Growth$	Energy consumption annual growth	%
$OPEX\_Losses(t)$	Costs related to losses at time $t$	M€
$Losses$	Energy losses as a share of energy consumption	%
$Energy\_Price$	Wholesale electricity price	€/MWh
$OPEX\_tot(t)$	OPEX at time $t$	M€
$Allowed\_ROA(t)$	Allowed maximum return on assets at time $t$	M€
$r$	Allowed rate-of-return on assets	%
$Revenues\_Lim(t)$	Maximum revenues due to the limited increase in tariffs at time $t$	M€
$limit$	Limited annual increase in tariffs	%
$Revenues(t)$	Revenues at time $t$	M€

<i>Tariffs(t)</i>	Transmission tariffs at time <i>t</i>	(€/MWh)
<i>Revenues_after_Debt(t)</i>	Revenues after debt servicing at time <i>t</i>	M€
<i>Interest_Rate</i>	Interest rate on debt	%
<i>Debt(t)</i>	Volume of debt at time <i>t</i>	M€
<i>Tax_Rate</i>	Corporate Tax rate	%
<i>Taxes(t)</i>	Corporate taxes paid at time <i>t</i>	M€
<i>Div(t)</i>	Dividends emitted at time <i>t</i>	M€
<i>Payout</i>	Dividend pay-out ratio	%
<i>Retained_Earnings(t)</i>	Retained earnings at time <i>t</i>	M€
<i>Fin_Needs(t) =</i>	Financing needs at time <i>t</i>	M€
<i>Equity_Injection</i>	Share of the financing needs injected as equity	%
<i>Equity(t)</i>	Volume of Equity at time <i>t</i>	M€
<i>Gearing(t)</i>	Gearing at time <i>t</i>	%
<i>Adjusted_ICR(t)</i>	Adjusted Interest Cover Ratio at time <i>t</i>	
<i>Effective_ROA(t)</i>	Effective rate of return on assets at time <i>t</i>	%
<i>Effective_ROE(t)</i>	Effective rate of return on equity at time <i>t</i>	%
<i>Effective_ROE_Div(t)</i>	Effective rate of return on equity paid as dividends at time <i>t</i>	%

### ***Regulated asset base and Depreciation costs***

Depreciation  $Dep(t)$  is linear in our analysis. We considered that new assets would have a depreciation period  $T$  equal to 40 years. This figure is in line with the data provided within the TSO annual reports and the analysis developed in the IEA WEO 2011.

Using TSOs annual reports, it was estimated that the average remaining lifetime of the existing ENTSO-E network was equal to 20 years  $T_0$ .

$$Dep(t) = \frac{RAB(0)}{T_0} + \sum_{i=Max(0,t-T)}^t \frac{Inv(i) + RenewInv(i)}{T} \quad (1)$$

The regulated asset base  $RAB(t)$  increases with investments related to new projects  $Inv(t)$ , investments for network refurbishing  $RenewInv(t)$  and is reduced by depreciation  $Dep(t)$ . The initial regulated asset base  $AverageRAB(0)$  was estimated from TSO reports to be initially equal to € 65 billion.

$$RAB(t) = RAB(t - 1) + Inv(t) + RenewInv(t) - Dep(t) \quad (2)$$

### **Network-related OPEX**

In this study, network-related OPEX costs are considered to be proportional to the length of the existing network  $Network\_Length(t)$ . Based on data from RTE 2011 annual report, OPEX costs  $UC\_OPEX$  were estimated to be equal to 0.014 M€2012/km. In this study, we assumed that no efficiency gain would be achieved by the TSOs.

$$OPEX\_Network(t) = Network\_Length(t) \times UC\_OPEX \quad (3)$$

The initial length of the electricity transmission network  $Network\_Length(0)$  was estimated to 305,000 km by ENTSO-E within the TYNDP 2012.

In order to calculate the growth of the network length, we employed a growth factor  $g$  equal to 1.90 M€2012/km for new investments, based on the figures provided within the TYNDP framework.

$$Network\_Length(t) = Network\_Length(t - 1) + \frac{Inv(t)}{g(t)} \quad (4)$$

### **Network losses**

In our analysis, network losses are directly proportional to the total energy consumption  $Cons(t)$ . The ratio was taken from the ENTSO-E memo 2010, which indicated a ratio  $Losses$  equal to 1.5% of energy consumption for network losses at the scale of ENTSO-E.

$$OPEX\_Losses(t) = Cons(t) \times Losses \times Energy\_Price \quad (5)$$

The initial consumption  $Cons(0)$  for the ENTSO-E area was extracted from the ENTSO-E System adequacy retrospect 2011 indicating a consumption of 3320 TWh in 2011. For annual consumption growth  $Cons\_Growth$ , we used a value provided within the *System*

*Outlook and Adequacy Forecast* edited by ENTSO-E (2012), indicating an annual growth of 0.77% for electricity consumption over the next decade.

$$Cons(t) = Cons(t - 1) \times (1 + Cons\_Growth) \quad (6)$$

For wholesale electricity prices *Energy\_Price*, we used a constant real value of 55€/MWh, in line with current prices (See for instance the Quarterly report on European electricity markets edited by DG energy). Note that there are high uncertainties regarding the evolution of electricity prices but that their impact on TSOs' financial ratios is limited as costs are passed through to consumers.

### **Return on assets and tariffs**

The maximum TSOs revenue *Allowed\_ROA(t)* is the product of the allowed rate-of-return *r* and of the value of the regulated asset base *AverageRAB(t)*.

$$AverageRAB(t) = RAB(t - 1) + RAB(t) \quad (7)$$

$$Allowed\_ROA(t) = AverageRAB(t) \times r \quad (8)$$

In the case when the increase in tariffs is not limited, tariffs are calculated so that they are equal to the sum of passed-through costs (Network-related OPEX *OPEX\_Network(t)*, network losses *OPEX\_Losses(t)*, and depreciation costs *Dep(t)*) and of the allowed-return. In the case when the increase in tariffs is limited to the current trends *limit*, the return provided to the TSO is reduced in consequence to *Revenues\_Lim(t)*.

$$Revenues\_Lim(t) = Revenues\_Lim(t - 1) \times \frac{Cons(t)}{Cons(0)} \times (1 + limit)^t \quad (9)$$

$$OPEX\_tot(t) = OPEX\_Network(t) + OPEX\_Losses(t) \quad (10)$$

$$Revenues(t) = Min(Revenues\_Lim(t), Allowed\_ROA(t) + OPEX\_tot(t) + Dep(t)) \quad (11)$$

$$Tariffs(t) = \frac{Revenues(t)}{Cons(t)} \quad (12)$$

### **Interests on debts**

We picked a standard interest rate  $Interest\_Rate$  equal to 4.0%. The initial gearing (at the beginning of 2012) was calculated from TSOs annual reports and is equal, for an aggregated TSO of all the members of the ENTSO-E, to 58.9%. The corresponding initial volume of debt  $Debt(0)$  is hence equal to € 38 billion.

$$Debt\_Servicing(t) = Debt(t - 1) \times Interest\_Rate \quad (13)$$

$$Revenues\_after\_Debt\_Servicing(t) = Revenues(t) - Debt\_Servicing(t) \quad (14)$$

### **Corporate tax rate**

The central assumption for corporate tax  $Taxes(t)$  is a weighted average of the different corporation tax rates existing in Europe<sup>8</sup> (data for 2012 were extracted from the KPMG website). As EBIT is strongly related to the regulated asset base in our model, the weights employed were the national network lengths.

The resulting weighted-average corporate tax  $Tax\_Rate$  was 27%.

$$Taxes(t) = Max(0, Revenues\_after\_Debt\_Servicing \times Tax\_Rate) \quad (15)$$

$$Revenues\_after\_Taxes(t) = Revenues\_after\_Debt\_Servicing(t) - Taxes(t) \quad (16)$$

### **Dividends**

Dividends are calculated as a fixed proportion  $Payout$  of the revenues after interests and taxes  $Revenues\_after\_Taxes(t)$ .

$$Div(t) = Payout \times Revenues\_after\_Taxes(t) \quad (17)$$

### **Financing needs**

The first source of financing is the share of revenues after taxes that is not used to pay dividends  $Retained\_Earnings(t)$ .

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<sup>8</sup> Corporate taxes strongly vary (from 10% to 34%) among the countries concerned.

The remaining financing needs  $Fin\_Needs(t)$  are covered through equity  $Equity\_Issue(t)$ , to the extent of a constant ratio  $Equity\_Injection$  of the financing needs. The rest is covered through debt emission.

$$Retained\_Earnings(t) = Revenues\_after\_Taxes(t) - Div(t) \quad (18)$$

$$Fin\_Needs(t) = Inv(t) + RenewInv(t) - Retained\_Earnings(t) - Dep(t) \quad (19)$$

$$Equity\_Issue(t) = Fin\_Needs(t) \times Equity\_Injection \quad (20)$$

$$Debt(t) = Debt(t - 1) + Fin\_Needs(t) - Equity\_Issue(t) \quad (21)$$

$$Equity(t) = Equity(t - 1) + Retained\_Earnings(t) - Equity\_Injection(t) \quad (22)$$

### **Financial ratios**

The two main indicators we employed are based on definitions provided in Moody's (2009).

$$Gearing(t) = \frac{Debt(t)}{Debt(t) + Equity(t)} \quad (23)$$

$$Adjusted\_ICR(t) = \frac{Revenues}{Debt\_Servicing(t)} \quad (24)$$

Different returns are also taken into account in our analysis.

$$Effective\_ROA(t) = \frac{Revenues(t)}{AverageRAB(t)} \quad (25)$$

$$Effective\_ROE(t) = \frac{Revenues\_after\_Taxes(t)}{\frac{Equity(t-1)+Equity(t)}{2}} \quad (26)$$

$$Effective\_ROE\_Div(t) = \frac{Div(t)}{\frac{Equity(t-1)+Equity(t)}{2}} \quad (27)$$

# GENERAL CONCLUSIONS

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## 1 CONTRIBUTIONS OF THE PHD

The contributions featured in this thesis show how the changes occurring in the power system challenge the existing arrangements in power markets. They emphasize how large-scale integration of intermittent RES, which is often seen mostly as a source of technical problems, also gives rise to important economic questions. Four important issues have been tackled with a specific methodology.

### 1.1 On the nature of the RES integration challenge

First, we exposed in chapter 1 the economic nature of the RES integration challenge. The interactions between a generation mix in evolution and an existing set of market arrangements lead to an intricate set of issues. Price-reflectivity and finer definitions come at the cost of complexity and poor liquidity; incentives directed towards an active participation of intermittent RES are a source of risks that can hinder their development and make it more costly. It is difficult to include all the relevant factors in a model, and existing studies focus on a given aspect by neglecting many other angles of view. Thus, a thorough literature review is helpful to put into perspective the main discussions that can be found in the literature.

We were then able to identify two implicit paradigms in the literature: a “melting-pot” integration paradigm (same rules and remuneration for dispatchable generation and intermittent RES), and a “salad-bowl” integration paradigm (different rules and remuneration for dispatchable generation and intermittent RES). A review of the arguments in favour of each of these theoretical frameworks reveals that there is no significant theoretical obstacle to the implementation of the melting-pot paradigm. We showed that finer locational and temporary definitions of the products are a prerequisite to such a framework, but that the complexity of power markets will increase exponentially as the definitions get refined. Similarly, joint-optimisation across the sequence of markets would improve efficiency at the cost of simplicity. Our review highlighted these trade-offs and described how they will be impacted in a context of large-scale penetration of intermittent RES.

### ***On redesigning the sequence of markets: the case of intraday markets***

As their production is not perfectly predictable, the development of intermittent RES will lead to higher exchanges of energy closer to real-time. Intraday markets could allow intermittent RES to reduce their exposure to high imbalances in balancing markets. The potential of intraday markets has been discussed both in empirical analyses and power system simulations. However, in empirical studies it is difficult to isolate the impact of a single component, such as the design of intraday markets. It is also challenging to extrapolate the results to a different generation mix with a high share of intermittent RES. In power system simulations, the results are highly dependent on fixed inputs such as the evolution of forecast errors and the technical parameters of the generation mix.

In chapter 2, by building a tailor-made analytical model, we have been able to focus on the key parameters, and to describe the relevance of different designs of intraday markets in a given power system for a given generation mix. In particular, we identified the correlation between forecast errors at different gate closures as a driver of the participation into intraday markets. Our results hence imply that the volumes of exchanges taking place in intraday markets could remain low for given sets of technical parameters.

### ***On exposing RES to market signals: economic curtailment of intermittent RES***

Curtailling the production of intermittent RES is a way to smooth out their variability, and hence to reduce the additional cycling costs for thermal generators. This intuitive result has been studied in seldom quantitative studies using power system optimisation models. Yet, such approaches do not allow considering a wide range of technical parameters (such as the flexibility of thermal generators or the variability of intermittent RES). Our approach in Chapter 3, based on a simple analytical model, has two major advantages. A first added-value of this approach is to describe the relationship between the pivotal parameters and the optimal level of curtailment. A second advantage is to assess the impact on each category of stakeholder. Indeed, a reduction of overall generation costs can lead to gains or losses for consumers, RES generators, and thermal generators.

By using this analytical model, we showed how the impact on the stakeholders will vary with the installed renewable capacity and the system flexibility. We also revealed that the owners of intermittent RES will have incentives to over-curtail or under-curtail the energy generated, and that this will be especially the case if intermittent RES and thermal generators are integrated within a single company.

These results illustrate how making intermittent RES more active, for instance through curtailment, can lead to efficiency gains when the share of intermittent RES gets significant. Yet, the efficiency gains achieved will have a very different impact on the main stakeholders. In particular, there are situations when the owners of intermittent RES will have little incentives to reach the optimal level of curtailment. Therefore, our findings highlight the importance of considering the distribution of efficiency gains when studying the benefits of curtailing intermittent RES. Decisions regarding the level of curtailment cannot be left to the generators. An alternative could be to let the TSOs set this level of curtailment, provided the TSO has access to good quality forecasts of RES production.

## **1.2 On the ability of European TSOs to finance the required transmission infrastructures**

Integration of intermittent RES is not only about designing the market to ensure economic efficiency: it is also a source of much more practical issues. In particular, the case of the substantial investments in the transmission networks (required to connect renewables) illustrates how even efficient investments generating value in the long term must cope with financeability constraints in the short term. In order to illustrate this somehow counter-intuitive idea, we have realised in chapter 4, a numerical simulation based on the actual balance-sheets of TSOs and investment plans of the European TSOs.

We have employed a balance-sheet model adapted to regulated assets with an allowed rate-of-return. By opposition to the existing quantitative studies focusing on network development to accommodate RES, we did not try to identify the efficient transmission projects, but rather focused on the evolution of the financial profile of the TSOs as these projects are realised.

This applied study exposed that barely half the investment programs could be achieved under current trends in tariffs, even in a best-case scenario of full cooperation between the European TSOs. Alternative financing strategies could mitigate this challenge, but only to a lower extent.

## **2 POLICY RECOMMENDATIONS**

### **2.1 On the rationale for RES integration into electricity markets**

Large-scale integration of RES is costly. As illustrated in Chapter 4, these costs will not be easily absorbed by conventional consumers and stakeholders when the development of RES becomes significant. It is important to acknowledge the costs, and the required evolution of energy prices and tariffs, that are associated to current ambitions and targets. Chapter

4 makes explicit the financing challenges associated to official targets for expansion of the transmission network.

As brute-force integration of passive RES is costly, smarter and more efficient solutions will be necessary. In particular, significant savings can be achieved by integrating RES into electricity markets. Chapter 2 shows how active management of RES production in intraday markets can reduce the costs of unpredictability. Chapter 3 explains how curtailment of renewables can lead to efficiency gains and mitigate the impact of variability of renewables. Anaya, K. L. and M. Pollitt (2013) showed how innovative commercial solutions could be found to integrate more efficiently distributed generation to the electricity network, so as to avoid some of the issues presented in Chapter 4. Some form of RES integration will in any case be necessary.

## **2.2 On electricity markets design in a context of large-scale RES integration**

Chapter 1 reviews the main arguments in favour of “melting-pot integration” and “salad-bowl integration”. After discussion, it appears that there is no theoretical obstacle to a single set of rules for both RES and conventional generators, once dynamic pricing is implemented. It is clear from this analysis that as the variability of renewables blurs the pattern of demand fluctuations, more accurate signals will be necessary. The implementation of refined temporal and locational signals is hence a prerequisite to RES integration, and should be a priority when redesigning energy markets. Melting-pot integration should then be implemented.

While a single set of rules can be used for both RES and conventional generators, it does not mean that the current rules will be adapted to a system with a large share of renewables. Chapter 1 explains how finer units, as well as a reorganisation of the sequence of markets, will be necessary. But it is also important to specify that a single set of rules will not be suitable to any system with a high share of RES. Chapter 2 and 3 illustrate how the nature of the conventional generation mix (costs and flexibility), as well as the physical properties of RES (flexibility and variability), drive the need for a specific set of market arrangements.

More specifically, Chapter 2 shows that a sequence of intraday markets might not fit the needs of RES managers, due to the evolution of forecast errors. It is then costly to restrict the possibilities of RES producers to these markets. It is also costly to compel participants to use these markets. Similarly, Chapter 3 shows that the gains and distributional effects of curtailing RES will vary significantly as the flexibility of the generation mix and the variability of RES evolve. These results emphasize that arrangements put into place to

ensure active participation of RES should take into account the needs of producers. As these needs are likely to evolve, any arrangement should be flexible enough to adapt to new conditions.

### **2.3 On issues of market structure**

One of the arguments supporting “salad-bowl integration” is the risks of abuse of market power from incumbents owning both conventional and RES generation. While we explain in Chapter 1 that there are more proper ways to deal with market power, the potential for such “integrated” utilities to exert market power is real.

Chapter 3 shows that when RES and thermal generators are integrated within the same company, RES will have indeed more incentives to depart from an optimal level of curtailment. The smaller the premium received by RES, the stronger these incentives. While such integration should allow joint optimisation and hence a more efficient operation of the generation park, abuses of market power could actually worsen things for the consumers. It is interesting that in this context, market power could not only be exerted by withdrawing capacity, but also by not withdrawing capacity when it would be more efficient. In such circumstances, the decisions of curtailing generation should be taken or monitored by a third agent, such as the TSO. Such curtailment options could be included in smarter connection arrangements mentioned in section 2.1.

Chapter 2 also illustrates that markets might not fit the needs of participants, which could give a strong advantage to utilities owning both RES and thermal generators. These utilities would then be able to manage their production internally, and more efficiently than the other participants. Implementing market arrangements flexible enough to accommodate the needs of RES generators would therefore help mitigating issues of market power.

## **3 POSSIBILITIES FOR FURTHER RESEARCH**

### **3.1 Collecting empirical evidence**

The core of this thesis is made of conceptual contributions. In order to support the insights delivered in these studies, a confrontation with empirical evidences would be needed.

#### ***Estimation of key parameters***

In order to support our findings, a first contribution of empirical work would be an assessment of the parameters highlighted in Chapter 2 and Chapter 3.

A first set of parameters to be estimated are RES properties: variability and unpredictability. In the case of unpredictability, it has been shown in Chapter 2 that a key parameter is the way forecasts oscillate when getting closer to the delivery time. Therefore, studying this phenomenon would bring significant added-value to the more classical evaluations of the size of the error (absolute value) when getting closer to the delivery time.

It is also important to distinguish the value of variability and unpredictability at the system level and at the generator level. While the latter allows a better understanding of actions taken by generators to manage their production, the former is often more easily accessible through the publications of system operators. Recent work by Schmalensee, R. (2013) illustrate the difficulties to obtain data for a truly random sample of individual plants.

A second set of parameters to be estimated are the system flexibility. Given the heterogeneity of existing plants in terms of age, use, and technology, it is not easy to estimate directly this flexibility. However, proxy could be found, such as for instance the impact on prices of unexpected events and strong variations of RES production.

### ***Testing the conceptual results developed in this thesis***

A first result of this thesis that could be submitted to empirical investigation is the role played by forecast errors oscillations on the use of intraday markets. Econometrical studies such as the one recently developed by Hagemann, S. and C. Weber (2013) for the German market try to determine the role played by fundamental drivers such as intraday deviations from the day-ahead planning. An interesting extension would then be to include the impact of oscillating predictions on the volume of energy traded in intraday markets.

A second insight of this thesis that could be submitted to empirical investigation is the potential abuse of market power by utilities owning both RES and thermal generators. In this context, the Spanish experience is especially interesting. Indeed, the Spanish electricity market features remuneration based on wholesale market prices, non-compensated curtailment of RES plants, ability to keep production below the maximum output by adjusting the blade pitch, and finally integration of wind farms and thermal generators within companies like IBERDROLA.

## 3.2 Releasing modelling assumptions

### *Taking demand-side management into account*

In our approach, the demand for electricity is taken as an inflexible exogenous input. It is likely that part of the needs for flexibility could be met by variations of the demand itself, as active consumers react to scarcity prices. Taking the potential of demand side management in our analytical studies in chapter 2 and 3 should then be extremely interesting.

### *Interactions between several participants*

In order to draw simple conclusions, we considered in our analytical approaches (Chapter 2 and 3) that the whole fleet of intermittent RES was managed by a single participant, or by participants with homogenous resources. A useful extension could then be to see how our results would be impacted in case of interactions between several participants in charge of resources with highly diverse profiles (for instance wind farms and concentrated solar power).

### *Disaggregation of the TSOs at a national level*

In Chapter 4, we made the assumption that the different European TSOs could be virtually integrated into a single European TSO. We were then focusing on financing constraints at the scale of the whole European industry. However, TSOs differ in terms of size, ownership, financial situation, and investment plans. It would be interesting to apply our approach to the different European TSOs, so as to obtain more specific results regarding the challenge of financing investments in the transmission network in a given country. It is then likely that more severe constraints would appear, for instance for small TSOs coping with high volumes of investment.



# RÉSUMÉ EN FRANÇAIS

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## Introduction

Afin d'éviter toute défaillance du système électrique, la production doit en permanence être égale à la consommation. Des ressources flexibles sont donc nécessaires pour pallier aux variations prévues et imprévues de la génération ou de la consommation.

En Europe, une part croissante du mix énergétique est constituée de sources d'énergie renouvelable (SER) dites intermittentes, comme les éoliennes ou les panneaux photovoltaïques. Ces unités de production sont isolées des signaux de marché par des mécanismes de soutien et de priorité. En outre, ces ressources présentent par définition des propriétés qui rendent plus difficile l'équilibrage du réseau. Tout d'abord, la quantité d'énergie qu'elles génèrent est tributaire des conditions météorologiques, et donc fortement variable. Ensuite, leur production n'est qu'imparfaitement prévisible. Ces variations doivent être compensées à l'aide d'un nombre réduit de centrales programmables, alors que le développement des SER intermittentes se fait plus pesant.

Tout au long de cette thèse, on considère que ces problèmes ne sont pas de nature technique, mais de nature économique. Les technologies flexibles requises pour gérer les particularités des SER intermittentes sont déjà connues, mais les incitations à les développer et à les opérer efficacement doivent encore être implémentées. En Europe, les signaux correspondants doivent être délivrés via la séquence de marchés qui coordonne les participants depuis le marché day-ahead (du jour précédent) jusqu'au marché en temps réel. Les programmes de production sont généralement établis dans le marché day-ahead, tandis que les écarts entre prévisions et production réalisée sont gérés dans les marchés d'ajustement proches du temps-réel. Afin de satisfaire les nouveaux besoins opérationnels, de nouveaux signaux de marché doivent refléter ces besoins, ainsi que la valeur de la flexibilité. En particulier, lorsque les prévisions relatives à la production des SER intermittentes s'améliorent nettement quelques heures avant l'horizon de production, le rôle prépondérant joué par le marché day-ahead tend à s'atténuer.

De plus, une troisième spécificité des SER intermittentes comme l'éolien est que les meilleurs sites de génération se situent souvent loin des centres de consommation. Des investissements importants doivent donc être réalisés dans le réseau de transport afin de connecter ces nouvelles unités. Des moyens de financement importants sont donc nécessaires, et ce dans un contexte de croissance limitée de la demande. Bien que les

gestionnaires du réseau de transport (GRT) européens reçoivent ex-post un revenu régulé, ils ont une capacité limitée à financer les investissements requis, dans un contexte de difficultés financières en Europe. La faisabilité de la vague d'investissements programmée n'est donc pas garantie.

Les SER intermittentes sont donc devenues un des moteurs des investissements et des opérations des réseaux électriques en Europe.

Une première question qui se pose est de savoir dans quelle mesure les SER intermittentes peuvent rester en dehors des marchés de l'électricité, alors qu'elles jouent un rôle-clé dans leur fonctionnement. Pérez-Arriaga, I. J. (2012) explique que les volumes d'énergie générée par les SER ont atteint un niveau ne leur permettant pas de rester passifs dans l'opération du réseau électrique et les marchés correspondants. En revanche, il est parfois argumenté qu'exposer les SER intermittentes à des signaux auxquels elles sont incapable de réagir risque de freiner inutilement leur développement (Batlle, C., I. J. Pérez-Arriaga and P. Zambrano-Barragán 2012, Klessmann, C., C. Nabe and K. Burges 2008).

Une seconde question est de déterminer dans quelle mesure le design de marché actuel est adapté à un système électrique contenant une part très importante de SER intermittentes (Green, R. 2008, Hogan, W. W. 2010). Les unités de temps employées pour définir les produits échangés ne sont pas appropriées dans un contexte de variabilité très importante de la génération des SER intermittentes. La faible-prévisibilité de leur production pourrait en outre remettre en question le rôle joué en Europe par le marché day-ahead précédent la production. Enfin, des signaux de localisation plus précis pourraient s'avérer nécessaires pour éviter des investissements trop importants dans le réseau de transport.

Après une discussion générale de ces problématiques et une revue de littérature dans le chapitre 1, cette thèse traite une série de questions découlant de chacune des spécificités des SER intermittentes. Le potentiel des marchés infra-journaliers pour gérer la faible-prévisibilité des SER intermittentes est évalué à l'aide d'un modèle analytique dans le chapitre 2. Le problème de la variabilité est abordé dans le chapitre 3 via un second modèle analytique traitant de la restriction de la production des SER intermittentes. Enfin on réalise dans le chapitre 4 une simulation numérique de l'évolution des bilans des GRTs européens, afin de souligner les difficultés posées par la connexion des SER intermittentes au réseau de transport.

## Chapitre 1 : Design des marchés d'électricité pour l'intégration des SER intermittentes

L'intégration des SER intermittentes est avant tout un problème de nature économique. Les solutions techniques existent, mais les incitations nécessaires pour en assurer un développement efficace doivent encore être mises en place. Dans ce chapitre, on présente la dimension économique du problème de l'intégration des SER intermittentes, et on confronte les principaux arguments développés jusqu'alors dans la littérature. Notre réflexion porte sur le fonctionnement d'un ensemble d'arrangements de marché confrontés à une évolution radicale du mix énergétique. De nombreux compromis en découlent : des définitions plus fines permettent une rémunération plus précise de la flexibilité mais elles constituent une source de complexité et de faible liquidité des marchés, tandis qu'un rôle actif des SER intermittentes risque de freiner leur développement et de le rendre plus coûteux. S'il est particulièrement difficile de développer un modèle qui prenne en compte tous ces aspects, une revue critique de littérature permet en revanche de donner une vue d'ensemble du problème.

Dans un premier temps, on s'interroge dans ce chapitre sur le modèle d'intégration des SER intermittentes. Dans de nombreux pays européens, ces ressources sont (au moins partiellement) isolées des signaux de prix dictant les opérations et les investissements des centrales thermiques conventionnelles. Les SER intermittentes bénéficient notamment de priorités et de primes à la production, ce qui en fait des unités peu réactives, dont la production est, de fait, traitée comme une demande négative. Bien que ces mécanismes de soutien soient justifiés afin d'assurer une dé-carbonisation rapide du mix énergétique, l'exposition des SER intermittentes aux signaux de marché doit être repensée quand elles constituent une part non-négligeable des moyens de génération.

On peut identifier dans les travaux existants sur le sujet deux paradigmes, qui sont souvent implicites. Le premier paradigme est celui d'une intégration de type « melting-pot » : après une phase de transition, les SER intermittentes pourraient être exposées aux mêmes règles que les générateurs contrôlables, et recevoir des rémunérations de nature similaire. Le second paradigme est celui d'une intégration de type « salad-bowl » : les SER intermittentes seraient de nature fondamentalement différente des autres générateurs, ce qui rendrait impossible toute intégration via les mêmes règles. Une discussion des arguments en faveur de chaque solution révèle que seule l'absence de signaux de prix dynamiques pour les consommateurs peut constituer un obstacle à une intégration de type

« melting-pot ». Cette solution s'avère en outre incontournable alors qu'une part très importante du parc de production est constituée de SER intermittentes.

Quel que soit le paradigme choisi, une révision des définitions des produits échangés dans les marchés de gros s'impose. Ces produits n'ont en effet pas été conçus pour assurer l'optimisation d'un système contenant de nombreux générateurs à la production très variable et peu prévisible. Des choix de simplification, et donc de définitions plus larges, ont été faits afin de favoriser l'émergence d'un marché liquide européen. Les conséquences de ce manque de précision dans les unités temporelles et spatiales se font plus lourdes avec le développement à grande échelle des SER intermittentes. Des définitions temporelles plus fines permettent ainsi aux ressources flexibles de recevoir une rémunération adaptée, et de réduire la socialisation des coûts de la flexibilité par le GRT. Toutefois, ces définitions plus fines rendent plus complexe l'internalisation des coûts non-convexes des générateurs (tels que les coûts de démarrage). De même, il existe un fort rationnel pour des définitions spatiales plus fines (jusqu'à des prix nodaux). D'une part, des signaux de prix plus fins permettraient d'éviter que les SER intermittentes optent pour les sites les plus coûteux à connecter, et donc des investissements importants dans le réseau de transport. D'autre part il est peu probable que des définitions spatiales relativement larges correspondent à la réalité physique du réseau et aux zones de congestion à chaque instant, dans un contexte de génération fortement variable.

Les limites de prix dans le marché de gros pourraient également être amenées à évoluer. Si les prix plafonds existant en Europe ne semblent pas pour l'instant constituer une contrainte effective, l'absence de prix négatifs, ou leurs planchers, semblent en revanche limiter fortement l'expression par les générateurs de leur flexibilité. De plus, les différences existant entre les prix-planchers dans des systèmes interconnectés sont une source de distorsion des flux d'énergie échangée.

Au delà des définitions employées à chaque pas de la séquence de marchés, le rôle de chacun de ces pas est également amené à évoluer. En effet, le rôle prépondérant du marché day-ahead ne correspond pas à la nature des SER intermittentes à la production peu prévisible. La part des échanges réalisés dans les marchés intraday (infra-journaliers) ainsi que dans les marchés d'ajustement en temps-réel est amenée à augmenter avec le développement des SER intermittentes. Il est donc capital que la cohérence entre les différents marchés soit assurée, depuis le marché day-ahead jusqu'au temps réel. Les définitions des produits échangés doivent être identiques dans chaque marché, ainsi que les limites de prix. Les pénalités dans le marché de temps réel doivent être supprimées.

Enfin, l'optimisation simultanée des marchés de l'énergie et des produits de réserves pourrait être favorisée par des arrangements de type pool.

Finalement, pour certains auteurs, le développement de SER intermittentes (ayant un coût marginal de génération nul) impose la mise en place de mécanismes de rémunération de la capacité. Toutefois, il n'est pas facile aujourd'hui de distinguer les effets transitoires (dus à un développement soudain de ressources isolées des signaux de marché) et les effets plus structurels (résultants de la coexistence de ressources fondamentalement différentes). De plus, la pertinence de ces mécanismes de rémunération de capacité dans un contexte de développement en masse des SER intermittentes dépend de leur capacité à rémunérer la flexibilité des ressources y participant. Cela impose des définitions temporelles et spatiales aussi fines que celles des produits d'énergie, ce qui constitue une source supplémentaire de complexité.

Quatre recommandations sont donc formulées pour conclure cette discussion. Tout d'abord, une intégration de type « melting-pot » doit être privilégiée. Ensuite, la définition des produits échangés devra évoluer, avec notamment des unités temporelles et spatiales plus fines, et des prix négatifs très bas. L'optimisation conjointe des différents marchés (y compris les marchés de réserve) devient clé et requiert davantage de cohérence entre ces différents produits. Enfin, les mécanismes de rémunération de capacité ne sont à priori pas nécessaires, et risque d'ajouter une couche superflue de complexité aux marchés existants.

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## **Chapitre 2 : Gestion centralisée de la faible-prévisibilité de la production des éoliennes par les marchés infra-journaliers**

La faible-prévisibilité de la génération des éoliennes constitue un des principaux obstacles à leur intégration dans les marchés de l'électricité. Dans ce chapitre, on s'intéresse au potentiel des marchés intraday comme facilitateur de l'intégration de SER intermittentes. En effet, les prévisions de génération s'améliorent de façon significative quelques heures avant l'horizon de production. En permettant aux producteurs éoliens d'ajuster à ce moment-là les engagements pris dans le marché day-ahead, il est en théorie possible de réduire le coût des écarts auxquels ils ont exposés dans les marchés de temps-réel. Cet

exemple illustre comment la séquence de marchés peut-être réarrangée pour permettre un rôle plus actif des SER intermittentes.

Les marchés infra-journaliers ont déjà été mis en place dans la plupart des pays européens, mais les designs existants sont assez éclectiques. Certains présentent une série discrète d'enchères (Espagne, Italie) tandis que d'autres sont des marchés continus (Allemagne, Danemark, France). Toutefois, même dans les pays où le développement des SER intermittentes est déjà important, la liquidité (définie comme le volume des échanges) dans ces marchés reste faible. Des règles supplémentaires ont parfois été introduites pour obliger les acteurs à participer dans ces marchés infra-journaliers. En Allemagne, depuis 2010, les GRTs (qui gèrent une partie de la production des éoliennes) doivent ainsi systématiquement corriger dans le marché intraday les écarts entre les engagements pris dans le marché day-ahead et les nouvelles prévisions disponibles. Dans ce chapitre on s'intéresse au coût de telles mesures, c'est-à-dire aux conditions sous lesquelles une gestion active de la production des SER intermittentes dans les marchés intraday peut être source de gains d'efficacité.

Le potentiel des marchés intraday a fait l'objet d'analyses empiriques, et a également été étudié à l'aide de simulations de réseaux électriques. Toutefois, il est difficile dans les études empiriques d'isoler l'effet d'un élément particulier, tel que le design des marchés intraday. Il est également délicat d'extrapoler les résultats à un mix de génération très différent, comprenant par exemple une part très importante de SER intermittentes. Les simulations de réseaux électriques sont quant à elles dépendantes de données d'entrée souvent fixées, telles que l'évolution des erreurs de prévision, ou la flexibilité du parc de génération. Dans ce chapitre, on emploie un modèle analytique spécifique au problème étudié. Cela nous permet de comprendre comment un certain design de marché intraday peut se montrer pertinent ou non, en fonction de la nature du mix de production et de l'évolution des erreurs de prévision des SER intermittentes.

On se concentre dans ce chapitre sur les effets de la faible-prévisibilité pour une période de production donnée, et on ne paie donc pas attention aux problèmes liés à la variabilité de la production entre deux périodes consécutives de production. On suppose de plus que les générateurs éoliens sont sous la responsabilité d'un acteur unique qui prend un engagement de production dans le marché day-ahead. Du fait des erreurs de prévision, cet acteur est exposé au coût des écarts lorsque la production réelle est différente de la position financière correspondante. Cet acteur a également la possibilité, à chaque étape du marché intraday, d'ajuster sa position auprès de générateurs programmables. Il utilise alors les prévisions les plus récentes qui soient disponibles. Un paramètre reflétant la

flexibilité du système est également introduit. Du fait de cette flexibilité limitée, il est plus coûteux pour les générateurs programmables de fournir l'énergie dans un délai très court.

On utilise ce modèle afin d'étudier les gains d'un gestionnaire très actif, employant les meilleures prévisions disponibles afin d'ajuster sa position à chaque étape du marché intraday, et on compare ces gains à ceux d'un gestionnaire ayant une attitude plus passive. L'intuition derrière nos résultats est la suivante : il est moins coûteux de gérer les écarts plus tôt par rapport à l'horizon de production, mais il existe un risque de corriger plusieurs fois des déviations qui se compenseraient de façon naturelle en l'absence d'intervention. Cela nous permet d'établir des seuils critiques pour les propriétés de l'évolution des erreurs de prévision. Les paramètres clés sont notamment l'écart-type des erreurs de prévision à un instant donné, la corrélation entre les erreurs à différents instants, et l'évolution des coûts lorsque le délai de production diminue.

Un premier résultat de notre analyse est qu'un comportement rationnel des participants peut conduire à un faible volume d'échanges dans les marchés intraday, pour certaines valeurs des paramètres techniques identifiés comme jouant un rôle clé. En particulier, la nature des prévisions accessibles aux producteurs peut les dissuader de participer aux marchés intraday. Des prédictions oscillantes (c'est-à-dire dont le signe de l'erreur évolue au cours du temps) rendent coûteux un usage actif des marchés intraday, lorsque le système est suffisamment flexible pour éviter des prix très élevés dans les marchés de temps-réel. Cette intuition a déjà été exposée dans quelques travaux référencés dans ce chapitre, mais on démontre ici le rôle essentiel de l'évolution des prévisions, et notamment de la corrélation entre les erreurs à chaque étape des marchés intraday. Lorsque la valeur de ce paramètre est faible (prédictions oscillantes), le gain d'information (réduction de l'écart type des erreurs de prévision) doit être suffisamment élevé pour justifier un ajustement de la position dans le marché intraday. Dans le cas contraire, les gestionnaires de la production des éoliennes n'ont pas intérêt à participer dans les marchés intraday. Le volume des échanges restera faible dans les marchés intraday car ces marchés ne répondent pas aux besoins des participants.

Un deuxième résultat, qui découle naturellement du premier, est qu'une obligation faite aux acteurs de participer dans les marchés intraday peut se révéler contre-productive. Tant que les conditions techniques demeurent insatisfaisantes, il n'est pas possible d'accroître à la fois la liquidité et l'efficacité par un changement de règles. Il va de soi qu'une telle obligation résulte mécaniquement en une hausse des échanges dans les marchés intraday, mais elle conduit tout aussi mécaniquement à une hausse du coût des

ajustements. La hausse des volumes ne doit pas être un objectif en soi des régulateurs : le volume des échanges augmentera (ou décroîtra) spontanément suite au développement des SER intermittentes ou des évolutions technologiques. Un prérequis reste bien entendu l'existence d'un marché intraday permettant aux producteurs d'y participer. Lorsque les outils de prévision seront devenus satisfaisants, les producteurs adopteront alors volontairement une stratégie active afin de minimiser leurs coûts.

De même, l'imposition dans les marchés en temps-réel de pénalités, ayant pour but d'inciter les acteurs à équilibrer leur position plus tôt, augmente artificiellement le coût des échanges en temps-réel, et pousse les producteurs à participer au marché intraday. La participation accrue dans les marchés intraday vise alors à couvrir les risques de coûts excessifs des écarts. Toutefois, les coûts de génération ne sont pas transformés par de telles pénalités financières, et les ajustements supplémentaires qui en résultent ne sont pas efficaces.

Enfin, cette analyse nous permet d'obtenir une troisième série de conclusions en comparant deux types de design principaux : marchés continus ou succession discrète d'enchères. Dans un marché continu, les acteurs sont libres d'émettre des offres à tout instant, et deux offres compatibles sont immédiatement traitées. L'alternative consiste en une série d'enchères discrètes avec un prix d'équilibre établi à intervalles réguliers. Par opposition aux marchés continus, les enchères discrètes ne permettent donc aux différents acteurs d'échanger que lors de ces enchères, dont l'heure est fixée au préalable. Il ressort de notre analyse qu'un acteur n'aura intérêt à exploiter la possibilité d'ajuster sa position à un instant donné du marché intraday que sous certaines conditions, qui lui sont en partie spécifiques. Alors que cet acteur aura dans un marché continu la liberté d'échanger aux moments qui lui sont favorables, cette possibilité sera plus restreinte dans un marché organisé autour d'une série d'enchères ayant lieu à heure fixe. Si les échéances imposées ne lui conviennent pas, cet acteur ne participera alors pas au marché intraday. C'est pourquoi on conclue dans cette analyse que restreindre les échanges à certaines échéances fixes (comme c'est le cas lors d'enchères discrètes) est une source d'inefficacité, de coûts supplémentaires, et d'opportunités d'échange gâchées.

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## Chapitre 3 : Restriction économique de la production des SER intermittentes

Même en faisant abstraction de leur faible-prévisibilité, les variations de la production des SER intermittentes rendent plus complexe l'opération du réseau électrique. La consommation, qui est relativement inflexible, doit être en permanence égale à la génération. Les variations de la génération des SER intermittentes, qui bénéficient de coûts marginaux nuls et sont appelées à produire en priorité, doivent donc être compensées par des variations inverses de la génération par les centrales programmables. Il est toutefois parfois coûteux, ou techniquement impossible, pour une centrale thermique de démarrer, ou de la rehausser, sa production suffisamment rapidement pour suivre les variations des SER intermittentes. Quand les surcoûts entraînés se révèlent trop importants, il est alors possible de réduire les coûts de génération totaux par des restrictions de la production des SER intermittentes (au coût marginal pourtant très faible).

On s'intéresse donc dans le chapitre 3 aux bénéfices qui peuvent résulter d'une restriction de la production des SER intermittentes. Ce chapitre illustre la façon dont un rôle plus actif des SER intermittentes peut réduire les coûts de génération. Ce résultat intuitif a déjà fait l'objet de quelques études se basant sur des simulations de réseaux électriques. Toutefois, de telles approches ne permettent pas de prendre en considération une large gamme de paramètres techniques, tels que la flexibilité des centrales programmables ou la variabilité de la production des SER intermittentes. On emploie ici un modèle analytique qui présente deux avantages. Premièrement, il permet de décrire le lien entre les paramètres pivots et le niveau optimal de restriction de la production. Deuxièmement, il est possible de différencier les gains (et les pertes) en résultant pour chaque catégorie d'acteurs : consommateurs, producteurs conventionnels, et SER intermittentes.

Afin de nous concentrer sur l'efficacité des opérations pour un parc de production déjà établi, on emploie un modèle de court-terme, dans lequel la capacité de SER intermittentes ainsi que celle des centrales thermiques installées sont des paramètres d'entrée déterminés de façon exogène. On considère également que les consommateurs ne réagissent pas au prix de l'énergie, et que la demande reste constante. Cette demande est couverte par la génération des SER intermittentes et des centrales contrôlables, qui offrent l'énergie qu'elles génèrent au coût marginal.

Puisqu'on s'intéresse aux conséquences de la variabilité de la production des SER intermittentes, on emploie un modèle portant sur deux périodes consécutives. La

disponibilité des SER intermittentes reste stable à l'intérieur de chaque période, mais est susceptible d'évoluer entre les deux périodes. La disponibilité des centrales contrôlables évolue également entre les deux périodes car les centrales qui n'ont pas généré d'électricité en première période sont bridées par des délais de démarrage et un rythme limité de hausse de la production. Il est possible de restreindre la production des SER intermittentes en première période, afin de ne pas avoir à redémarrer les centrales thermiques en deuxième période. Un compromis doit alors être trouvé entre les coûts supplémentaires engendrés en première période lorsque des ressources « gratuites » et renouvelables sont volontairement sous-exploitées, et les gains qui en résultent en deuxième période.

Le niveau optimal de restriction est défini comme celui minimisant les coûts de génération totaux sur les deux périodes. Ce niveau de production affecte les volumes générés et les prix atteints dans chaque période. Les gains par rapport à une situation sans restriction de la production en première période sont distribués entre les différents acteurs (consommateurs, SER intermittentes, et générateurs contrôlables). Grâce à notre approche analytique, basée sur un modèle relativement simple, nous sommes à même d'évaluer l'impact sur chaque catégorie d'acteurs. Cet impact est évalué pour différents modes de rémunération de la production des SER intermittentes (basé sur les prix du marché et avec ou sans premium), avec compensation ou non des restrictions de production imposées en première période.

Un premier résultat qui ressort de notre analyse est qu'il est bien rationnel de restreindre la production des SER intermittentes, lorsque leur disponibilité est grande et que le système est peu flexible. Plus précisément, il existe un seuil pour la capacité installée de SER intermittentes, au-delà duquel ces restrictions permettent de réduire les coûts de génération. Il est donc naturel de remettre en cause les mécanismes accordant la priorité de production aux SER intermittentes lorsque leur développement se fait trop important. Ce seuil ne dépend pas du mode de rémunération ou de compensation, mais il augmente avec la flexibilité des centrales contrôlables et diminue avec la variabilité des ressources intermittentes.

Il est ensuite possible de décortiquer ce résultat intuitif en évaluant l'impact sur les différents acteurs. L'effet sur les intéressés varie en effet en fonction de la capacité installée des SER intermittentes et de la flexibilité du système. Cette redistribution résulte d'abord d'un effet sur les prix, qui augmentent (réciproquement diminuent) lorsque des ressources au coût marginal nul sont retirées (insérées) dans la courbe d'offre. Elle résulte ensuite d'un effet sur les volumes générés par chaque catégorie de technologies. Ces deux

effets conduisent à des incitations parfois contraires. Les générateurs contrôlables bénéficient de restrictions lorsque la flexibilité du système est basse et lorsque la volatilité de la production des SER intermittentes est élevée, tandis que les consommateurs bénéficient de restrictions lorsque la flexibilité du système est élevée et lorsque la volatilité de la production des SER intermittentes est basse. Enfin, il est intéressant de constater que les SER intermittentes peuvent bénéficier de restrictions, même lorsque ces dernières ne sont pas compensées. C'est en particulier le cas lorsque la capacité installée de SER intermittentes est assez importante pour que les baisses de volumes dues aux restrictions soient compensées par la hausse des prix.

Bien que le niveau optimal de restriction ne dépende pas des modes de rémunération ou de compensation, ces derniers déterminent en partie la distribution des bénéfices en résultant. Lorsque les SER intermittentes reçoivent pleine compensation en cas de restriction, elles sont alors toujours bénéficiaires (grâce à l'effet prix) en cas de restriction. Lorsque les SER intermittentes ne reçoivent pas de compensation, elles ne sont bénéficiaires qu'à partir d'un certain niveau de production. Cela implique que tout mécanisme de compensation est amené à évoluer lorsque le mix énergétique évolue. Il est à noter que même en cas de compensation payée aux SER intermittentes, les consommateurs qui versent cette compensation peuvent bénéficier de restrictions lorsque les gains d'efficacité sur les coûts de génération sont suffisamment importants.

On constate donc que les niveaux de restriction maximisant les profits des générateurs et ceux minimisant les coûts de génération totaux sont rarement alignés. Ainsi, les générateurs ont tendance à trop restreindre la production lorsque la flexibilité du système est élevée et que la variabilité des SER intermittentes est faible. De manière symétrique, les générateurs tendent à ne pas restreindre suffisamment la production lorsque la flexibilité du système est basse et que la variabilité des SER intermittentes est élevée. Il existe une plage de paramètres techniques pour lesquels seuls les consommateurs bénéficient de restrictions au niveau optimal. Il est alors peu probable que ce niveau de restriction soit atteint via des mécanismes de marché dont les consommateurs sont relativement absents. L'intervention d'un agent comme le gestionnaire du réseau de transport pourrait alors s'avérer nécessaire. Il ressort également de notre analyse que cette intervention pourrait s'avérer d'autant plus nécessaire lorsque les générateurs intermittents et les générateurs contrôlables sont intégrés au sein d'une même compagnie.

Enfin, de nombreux problèmes d'asymétrie d'informations apparaissent lorsque le niveau de restriction est fixé par un tiers. Ainsi, les générateurs peuvent manipuler les informations qu'ils procurent à cet agent pour influencer le niveau de restriction. Quand la

variabilité de la production est faible et que la flexibilité du système est élevée, les générateurs intermittents ont par exemple intérêt à surestimer la variabilité. Ce problème peut être résolu en exposant les générateurs aux coûts résultants d'erreurs entre les prévisions et la production réalisée. Alternativement, le gestionnaire du réseau de transport peut centraliser la prédiction de la production, afin de disposer de données de qualité.

## **Chapitre 4 : Financement des développements du réseau de transport européen et conséquences sur la viabilité financière des gestionnaires du réseau de transport**

Le développement du réseau de transport d'électricité est amené à jouer un rôle prépondérant dans la stratégie de l'Union Européenne visant à intégrer au réseau une quantité importante de SER intermittentes. Cependant, les investissements substantiels qui sont programmés pourraient se révéler difficile à financer, y compris pour des entités régulées comme les gestionnaires du réseau de transport (GRTs). Afin d'établir l'ampleur de la difficulté, on réalise dans le chapitre 4 une simulation numérique de l'évolution du bilan des GRTs européens, à partir du bilan actuel des GRTs et des plans d'investissement européens.

De précédentes études, comme celle réalisée par le cabinet Roland Berger (2011), se sont intéressées au problème des besoins de financement en évaluant le volume d'investissement lors des vingt prochaines années et en le comparant aux volumes actuels. Ces calculs grossiers sont utiles pour poser le problème, mais ils ne prennent pas en considération l'impact sur les ratios financiers employés chaque année par les investisseurs pour évaluer la santé financière de l'entreprise. D'autres travaux visent à développer un cadre réglementaire adapté et des incitations appropriées pour que les investissements identifiés soient réalisés de manière efficace par les GRTs. Une bonne revue de ces travaux est par exemple disponible dans Guthrie, G. (2006).

L'approche employée dans ce chapitre diffère des travaux cités, puisqu'on se concentre sur l'évaluation de différentes stratégies de financement des GRTs, et leur aptitude à couvrir les besoins de capitaux des GRTs. Par opposition aux études existantes, on considère qu'un cadre réglementaire adapté est en place, et que les volumes de dette contractée restent disponibles à un coût raisonnable. On ne s'intéresse pas non plus à l'identification des projets créateurs de valeur, mais à l'évolution du profil financier du

GRT à mesure que ces projets sont exécutés. Le modèle du bilan employé est conçu pour une entité régulée, bénéficiant d'un retour sur investissement garanti. On y introduit également la possibilité de limiter l'évolution des tarifs dans le temps. On compare ensuite le coût, pour diverses stratégies financières, d'assurer le financement des projets identifiés par l'ENTSO-E (association des GRTs européens pour l'électricité), tout en conservant des ratios financiers satisfaisants. L'évaluation des ratios financiers suit la méthodologie quantitative employée par l'agence de notation Moody's.

Les programmes d'investissements employés sont définis dans des études de la commission européenne et le plan sur dix ans de l'ENTSO-E. Cette étude inclut en outre le coût du renouvellement du réseau existant, plus faible que celui des nouveaux projets mais loin d'être négligeable. On s'intéresse à l'évolution des contraintes financières pour un GRT européen unique, dans la zone de l'ENTSO-E, et sur la période 2012-2030. Cette hypothèse simplificatrice se justifie par une coopération et des relations accrues entre les GRTs membres de l'ENTSO-E. Le cas présenté dans cette étude est donc un scénario dans le meilleur des cas, et les contraintes susceptibles d'apparaître à une échelle nationale sont négligées.

Les résultats sont développés à la lueur de certaines intuitions formulées par Neuhoff, K., R. Boyd and J.-M. Glachant (2012) : les investissements dans le réseau de transport doivent être couverts par les tarifs chargés aux utilisateurs du réseau sur la durée de vie des actifs, et les GRTs ne peuvent se contenter de contracter des dettes pour financer initialement ces investissements. Afin de lever des fonds sur les marchés financiers à un coût raisonnable, les GRTs doivent respecter des contraintes sur leurs ratios financiers : poids de la dette par rapport à la valeur de l'entreprise, montant des intérêts par rapport aux bénéfices. On établit dans ce chapitre la capacité des GRTs à financer leur programme d'investissement sans dégrader leur profil financier. On mesure ainsi le déficit de financement pour différentes stratégies, et on calcule ensuite l'évolution des tarifs requise pour combler ce déficit.

Les GRTs peuvent financer les développements du réseau à l'aide de trois outils : en levant de la dette (auprès de banques, d'institutions, ou sous forme d'obligations), en conservant une partie des profits pour les réinvestir, ou en trouvant une source externe de fonds propres. Depuis la libéralisation, les GRTs ont traditionnellement eu recours à l'émission de dette, ce qui a conduit à des niveaux d'endettement qui sont aujourd'hui relativement élevés (60%-70% de la valeur de l'entreprise). Cela limite la capacité des GRTs à emprunter davantage sans dégrader leur notation. Le financement en interne par les bénéfices non-répartis est une source de fonds importante pour certains GRTs européens, mais il ne peut

suffire lorsque les besoins de financement augmentent de manière importante. De plus, les investisseurs traditionnels des GRTs préfèrent recevoir des dividendes élevés que de voir les bénéfices réinjectés dans l'entreprise. Enfin, alors que les GRTs européens sont souvent propriété des états, le recours à des sources de fonds propres externes peut s'avérer compliqué. D'une part les états sont limités actuellement par leurs propres contraintes budgétaires et sont dans ce cas enclins à réduire les investissements. D'autre part les états sont réticents à diluer leurs droits sur des biens d'utilité publique.

Ces trois sources de financement présentent donc des limites, et sont en conséquence complémentaires plutôt que substituables. On analyse dans ce chapitre le potentiel de trois stratégies de financement dont les caractéristiques sont basées sur les descriptions de Neuhoff, Boyd et al. (2012). Dans notre scénario de statuquo, les investissements sont financés à l'aide d'une petite partie des bénéfices et principalement par l'émission de dette. Dans le scénario « Injection de fonds propres », une part importante des besoins de financement provient d'injection externe de capitaux. Dans le scénario « Modèle de croissance », les versements de dividendes sont réduits et une part plus importante des bénéfices sont réinvestis dans l'entreprise.

Le premier résultat de cette étude est l'identification d'un déficit de financement important en cas d'évolution constante des tarifs. Dans notre scénario de statuquo, seule la moitié des projets identifiés par l'ENTSO-E pourrait être financée sans que les GRTs ne deviennent des investissements spéculatifs. Les tarifs de transport devraient doubler (en termes réels) d'ici 2030 pour financer l'intégralité des projets.

Le second résultat de cette étude est la confirmation que des stratégies de financement alternatives permettent de réduire les coûts pour l'utilisateur du réseau. Toutefois, cela impose un changement de la perception des propriétaires des GRTs envers l'entrée de nouveaux investisseurs et l'évolution du modèle d'entreprise. De plus, ces stratégies alternatives ne peuvent se substituer totalement à une hausse des tarifs, sous peine de rendre peu attractif le retour sur investissement.

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