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Pricing Renewable Energy in a Competitive Electricity Market

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Executive Summary – Pricing Renewable Energy in a Competitive Electricity Market

In Portugal, just like in other European countries, the production under special regime (PSR), i.e. production that uses renewable resources as fuel or combined heat and power plants (CHP), has benefited from several incentives, since its environmental impact is lower than the "classic" generation models. These incentives generally apply to the obligation of purchasing the electric energy produced by renewables, within a previously defined remuneration process.

Decree-Law number 225/2007 defines the parameters that allow determining the remuneration of the energy supplied to the public grid by the PSR, the so-called feed-in tariff. In this same Decree-Law, it is also explained the validity of this remuneration method, which depends on the technology. In the case of wind energy, the feed-in tariff is applicable to the first 33 GWh/MW injected in the grid or 15 years of installed power, which of the two occurs first. Once the limit is achieved, the annex of the same Decree-Law states that renewable energy units will be remunerated for the selling of energy at market prices and for the selling of green certificates.

The present work aims to establish a model for assessing wind energy revenue in MIBEL's (Iberian Electricity Market) power market. To that purpose, it is studied the introduction of a specific wind unit in MIBEL. Moreover, the functioning of MIBEL will be analysed, as the platform for the inclusion of wind energy in the power market. Particularly, it is implemented a simulator of the daily market.

The management of the organised markets of MIBEL is based on an interconnected bipolar structure, where the day-ahead and intraday markets are operated by the Spanish division (OMEL) and the organised derivatives market is under the responsibility of the Portuguese division (OMIP). MIBEL entities, though, have permanent cooperation. Only the markets operated by OMEL were used to study the introduction of a particular wind farm in the power market. The main purpose of the day-ahead market is to handle transactions for the following day through the presentation of selling and purchasing orders to the market operator, OMEL, who includes them in a matching procedure that comprises twenty-four consecutive programming hours. The intraday (ID) market is a vital tool for wind producers, as it is the last opportunity that market participants are offered to balance their schedules, i.e. it operates immediately before System Operator's balancing mechanisms.

The algorithm employed to compute the market simulator follows the market splitting mechanism, as it is the implicit capacity allocating method used by Portugal and Spain to assign interconnection capacity in the day-ahead timeframe. This mechanism is characterized by the following procedure: firstly the equilibrium price with orders from both countries is determined. Then, the resulting cross border flow origins two possible scenarios: if it does not exceed the net transfer capacity (NTC), the result is valid and both countries share the same equilibrium price; if it is higher than the NTC, the initial market with bids and asks from both countries is split into two separated markets, each one with its price.

The results of the market simulator consist of the relevant output for a market operator (clearing price and matched volume for the defined hourly period) as well as the aggregated supply and demand curves for a particular hour. Furthermore, it is relevant to mention that the results obtained were concordant with the ones of OMEL's public site.

Regarding the inclusion of the wind producer in the power market, the strategy performed should maximize the global economical results of the wind producer taking into account the overall operation cycle: day-ahead, intraday and system operation balancing. Consequently, it was decided that the optimal approach for the wind producer's perspective was correcting just once and in the last available intraday session for each hour the generation schedule made in the day-ahead market.

In order to analyse the introduction of a particular wind farm in the power market, six scenarios were built, to assess the influence of the main variables on the overall economic outcome of such an approach. Those scenarios correspond to six data-bases (DB1, DB2, DB3, DB4, DB5 and DB6) with the following features: all scenarios have the same day-ahead generation schedule and actual generation; DB1, DB2 and DB3 have in common one scheduling methodology, based on a physical meteorological wind generation forecast (NWP method); DB4, DB5 and DB6 have in common another ID scheduling methodology, based on a statistical signal processing wind generation forecast (ARMA method). For each of the group scenarios referred variations were made on day-ahead, intraday and balancing prices by using: exclusive Portuguese values (DB1, DB4), exclusive Spanish values (DB3, DB6) and a mix of Portuguese values complemented by Spanish values for intraday prices when there was no such price available in Portugal (DB2, DB5). All the information was gathered for the whole year of 2008 and in an hourly basis.

For each of those scenarios, the yearly revenue of the wind producer was calculated for three distinct strategies: (i) all the actual generation (AG) of the wind farm is injected in the transmission grid and priced at day-ahead market price (DAP), meaning that there are no deviations; (ii) the wind producer does not correct the day-ahead schedule (DAS) in the ID market, what implies that he exposes the difference between the AG and the DAS to the balancing prices of the system operator; (iii) the wind producer corrects each hour of the DAS in the ID market only once and in the last available ID session, exposing the difference between the AG and the correction in the ID market, named intraday schedule (IDS), to the balancing prices of the SO. Theoretically, analysing the three situations we conclude that in the first one the wind producer will have the highest revenue (upper limit – UL) and in the second one the lowest financial income (lower limit – LL), with the revenue in the third case being placed between those limits (intraday situation – ID), since it is the sole one in which the wind producer participates in the ID market.

The yearly revenues of the wind producer in the upper limit, lower limit and intraday situation (YR_{UL}, YR_{LL} and YR_{ID}, respectively) obtained with the contents of the six data-bases are summarized in Table a). Besides, in the same Table it is also included the average price, AP, at which the energy generated by the wind farm was valued.

Table a) – Summary of the yearly revenues of the wind producer and average price at which the energy he sold was valued.

DB	YR_{UL} (M€)	AP_{UL} (€/MWh)	YR_{LL} (M€)	AP_{LL} (€/MWh)	YR_{ID} (M€)	AP_{ID} (€/MWh)
DB1	18	67.95	15	56.63	15.1	57
DB2	18	67.95	15	56.63	15.2	57.38
DB3	16.6	62.67	15.6	58.89	15.7	59.27
DB4	18	67.95	15	56.63	14.8	55.87
DB5	18	67.95	15	56.63	14.7	55.49
DB6	16.6	62.67	15.6	58.89	15.61	58.93

It is clear in Table a) that the difference between the yearly revenue of the wind producer in the intraday situation and in the lower limit case was not as accentuated as it would be expected. The most significant aspect that contributed to this phenomenon was the inaccuracy of the adjustments effectuated in the ID sessions. Consequently, it was carried out a set of simulations to evaluate the impact on the YR_{ID} of an improvement of the corrections operated in the ID sessions. This improvement was accomplished by adding to the IDS in each hour, 25%, 50% or 75% of the initial difference between the AG and the IDS. Let us call the yearly revenues that derive from these adjustments in the IDS, YR_{25}, YR_{50}, YR_{75} and YR_{100} (assuming the wind producer corrected perfectly the forecast in the ID market). Figures a) and b) show the results of the adjustments for DB1 and DB2.

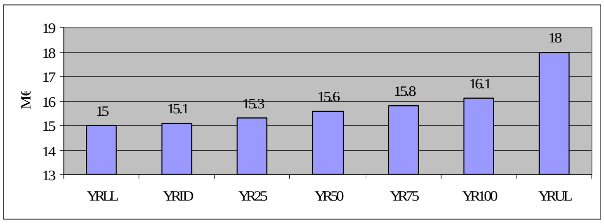

Figure a) – Results of the IDS adjustment in DB1.

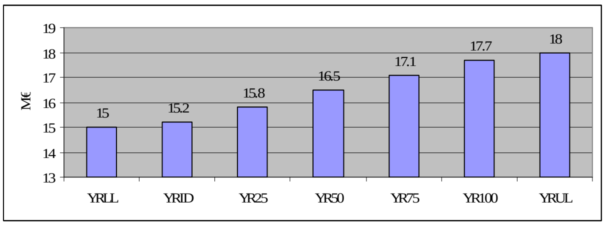

Figure b) – Results of the IDS adjustment in DB2.

In Figure a) the impact of the forecast accuracy improvement is unperceived, since in Portugal in 2008 there were over 63% of the hours that had no ID price. Yet, in Figure b) that impact is evident, due to the existence of prices in all ID sessions. The difference between the YR_{LL} and the YR_{75} rises to over 2 M€.

One of the main conclusions of this work is that the actual revenue of the wind farm, based on the feed-in tariff regime (24.2 M€), exceeds largely all scenarios revenues, determined in each of the six data-bases (Table a)). However, it must be pointed out that the item related to the selling of green certificates was not taken into account. Furthermore, the yearly revenue of wind producers, with their inclusion in the power market, will be function of highly unpredictable variables: day-ahead prices, ID prices and balancing prices. This means they will not be able to forecast the price at which they will sell their energy, in opposition to the tariff regime. In addition, it was also verified that the difference between the yearly revenue of the wind producer in the upper and lower limit situations calculated with the Spanish market prices (DB4, DB5, DB6), 1 M€, was significantly smaller than the one determined with the prices of the Portuguese area (DB1, DB2, DB3), 3 M€. This feature allowed concluding that the Spanish balancing prices are more in line with the day-ahead prices and that the Portuguese ones penalise more severely the wind producer. To overtake this drawback, Portuguese agents could be consented to have access to the Spanish balancing market (and vice-versa). Moreover, a crucial issue of the introduction of wind producers in the power market is the ID markets. In 2008, there was lack of liquidity in the ID prices of the Portuguese area. This lack of liquidity can be a strong drawback for wind producers as they need the ID platform to perform the corrections to the day-ahead schedule. Still, the good news is that the entry of new players in the market, namely wind producers, is likely to foster liquidity. Another relevant remark of this work is that wind producers, in order to have the best possible financial income, will have to find the optimal equilibrium between ID price liquidity and forecast reliability.

In Table a), it can also be witnessed that the differences between the yearly revenue of the wind producer in the ID situation and in the lower limit case were not as accentuated as expected. This occurred mainly due to the inaccuracy of the wind power forecasts utilized to perform the corrections in the ID markets. Actually, both NWP and ARMA models used in this study had some drawbacks. The NWP forecast did not contain information related with persistence, while the ARMA model had some negative aspects regarding the training period. These two issues made it impossible to extract the maximum potentialities of both methodologies. Nevertheless, once the NWP methods have a better behaviour for time horizons superior to 3 hours and ARMA models are likely to offer accurate forecasts within a time horizon of 30 minutes to 3 hours, we anticipate that the optimal strategy for wind producers when participating in the power market would be to use NWP methods to execute the day-ahead schedule (DAS) and ARMA models to perform the intraday adjustments (IDS).

Abstract

The various energy crises that have hit the world together with a growing awareness of environmental matters have raised strong concern about issues like sustainability, security of supply and competitiveness. In the European Union promotion of renewable energies, in particular wind energy has become one fundamental vector of the strategy to tackle those challenges.

Portugal is already among the world top ten countries in installed wind power capacity, as a result of a sustained policy of supporting that technology followed by several Governments through an aggressive feed-in tariff model, which is applicable for a definite period of the project's lifecycle, after which the legislation establishes a remuneration method based on market prices.

This work's purpose is to analyse, from a technical and economical perspective, the operation of a wind producer installed in Portugal when, in the future, he will have to sell his energy into the market, in a regional integrated market framework (MIBEL). Accordingly, a simulation of MIBEL day-ahead market is implemented using a market splitting model and the economic outcome of a wind farm operating in that market is assessed, considering various strategies.

The results gathered show that the new regime remuneration is highly dependent on various factors, namely market prices volatility, production forecast accuracy, balancing prices and liquidity and frequency of intraday markets. Some measures are also identified that mitigate some drawbacks associated to the wind farm operation in a market environment.

Keywords: Market, Market Splitting, MIBEL, Generation Forecast, Wind Producer.

Resumo

As várias crises energéticas que abalaram o mundo, associadas a uma crescente tomada de consciência para os problemas do ambiente fizeram emergir temas essenciais como a sustentabilidade, a segurança do abastecimento e a competitividade. Na União Europeia a aposta nas energias renováveis e, em particular, na energia eólica, constitui um dos vectores essenciais da estratégia para enfrentar esses desafios.

Portugal encontra-se já no "top 10" mundial em termos de potência eólica instalada, graças a uma política sustentada por vários Governos de apoio a essa tecnologia através de um modelo remuneratório de tarifa "feed in", bonificada e aplicável a um período definido da vida do empreendimento, após o qual a legislação define uma remuneração baseada em preços de mercado.

O presente trabalho tem como objectivo a análise técnico-económica do funcionamento de um produtor eólico instalado em Portugal quando no futuro a energia produzida for colocada em mercado, num ambiente de mercado regional integrado (MIBEL). Para o efeito, simula-se o funcionamento do mercado à vista do MIBEL, no modelo de separação de mercados e avaliam-se os resultados económicos da colocação da energia de um parque eólico nesse mercado considerando diversas estratégias de actuação.

Os resultados obtidos evidenciam uma elevada dependência da nova remuneração face a vários factores, nomeadamente volatilidade dos preços de mercado, exactidão da previsão da produção, preços de desvio e liquidez e frequência dos mercados intradiários, apresentando-se no final algumas propostas de mitigação dos impactos negativos observados.

Palavras-chave: Mercado, MIBEL, Previsão Produção, Produtor Eólico, Separação Mercados.

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Abbreviations

ABP	Average Buying Price
ACE	Area Control Error
AG	Actual Generation
AIC	Akaike Information Criterion
AiPT	Portuguese selling order
AiES	Spanish selling order
AP_{ID}	Average Price in the Intraday situation
AP_{LL}	Average Price in the Lower Limit situation
AP_{UL}	Average Price in the Upper Limit situation
AR	Autoregressive
ARMA	Autoregressive Moving Average
AskVolume(Pi)	Aggregated volume of ask orders with prices ≤ Pi
$AskVol_{PT}$	Aggregated volume of Portuguese ask orders with prices smaller or equal to the equilibrium price
ASP	Average Selling Price
AV	Ask Volume
AVG	Average
BIC	Bayesian Information Criterion
BidVolume(Pi)	Aggregated volume of bids orders with prices ≥ Pi
$BidVol_{PT}$	Aggregated volume of Portuguese bid orders with prices higher or equal to the equilibrium price
BiES	Spanish purchasing order
BiPT	Portuguese purchasing order
BP	Balancing Price
BPD	Balancing Price Downwards
BPD_{PT}	Balancing Price Downwards of the Portuguese area
BPD_{SP}	Balancing Price Downwards of the Spanish area
BP_{PT}	Balancing Price of the Portuguese area

BP_{SP}	Balancing Price of the Spanish area
BPU	Balancing Price Upwards
BPU_{PT}	Balancing Price Upwards of the Portuguese area
BPU_{SP}	Balancing Price Upwards of the Spanish area
BV	Bid Volume
CA	Corrective Action
CBF	Cross Border Flow
CCGT	Combined Cycle Gas Turbine
CET	Central European Time
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
c€	cent Euro
DAP	Day-Ahead market Price
DAP_{PT}	Day-Ahead market Price of the Portuguese area
DAP_{SP}	Day-Ahead market Price of the Spanish area
DAP_{2007}	Average Day-Ahead market Price of 2007
DAP_{2008}	Average Day-Ahead market Price of 2008
DAP_{2009}	Average Day-Ahead market Price of 2009
DAS	Day-Ahead Schedule
DB	Data Base
diff	Difference between actual generation and intraday schedule
DRP	Day-ahead Reference Price
DSV	Delivery Settlement Value
EC	European Commission
EDIA	Empresa de Desenvolvimento de Infra-estruturas do Alqueva
EDP	Energias De Portugal
EDP SU	Energias De Portugal, Serviço Universal
EEG	Erneuerbare Energien Gesetz
EP	Equilibrium Price
ERSE	Entidade Reguladora dos Serviços Energéticos

EU	European Union
EWEA	European Wind Energy Association
FDD	First Day of the Delivery period
FPi	Final Position on futures contract "i"
FSP	Final Settlement Price
FTD	First Trading Day
FTRs	Financial Transmission Rights
GCT	Gate Closure Time
GW	Gigawatt
GWh	Gigawatt hour
H	Number of delivery hours on "d" delivery day
i	Futures contract with delivery on "d" day
ID	Intraday
IDP	Intraday Price
IDP_{PT}	Intraday Price of the Portuguese area
IDP_{PT+SP}	Mix of Portuguese intraday prices complemented by Spanish intraday prices when there was no such price available in Portugal
IDP_{SP}	Intraday Price of the Spanish area
IDS	Intraday Schedule
IDS_{25}	Intraday Schedule accuracy improvement by adding to the IDS_{NWP} 25% of diff
IDS_{50}	Intraday Schedule accuracy improvement by adding to the IDS_{NWP} 50% of diff
IDS_{75}	Intraday Schedule accuracy improvement by adding to the IDS_{NWP} 75% of diff
IDS_{100}	Intraday Schedule accuracy improvement by matching the IDS with the actual generation
IDS_{ARMA}	Intraday generation Schedule based on ARMA models
IDS_{NWP}	Intraday generation Schedule based on NWP methods
IF	Interconnection Flow (cross border scheduled flow)
K_{IPC}	Correction according to the inflation applied to the remuneration of the PSR
K_p	Parameter that books the losses prevented
k_{pt}	Correction that depends on the diagram of energy production
kW	kilowatt

kWh	kilowatt hour
LAF	Last Available Forecast
LDD	Last Day of the Delivery period
LL	Lower Limit
LTD	Last Trading Day
MA	Moving Average
MIBEL	Mercado Ibérico de Electricidade
MO	Market Operator
MP	Market Price
mP	minimum Price
$\mathbf{MP_{PT}}$	Market Price of the Portuguese area
$\mathbf{MP_{SP}}$	Market Price of the Spanish area
MTM	Market-To-Market
MTV	Maximum Tradable Volume
MW	Megawatt
MWh	Megawatt hours
M€	Million Euros
n	Total number of futures contracts with delivery on “d” day
NEC	Net Exporting Curve
NTC	Net Transfer Capacity
NWP	Numeric Weather Prediction
OMEL	Operador do Mercado Ibérico de Energia – Pólo Espanhol
OMIP	Operador do Mercado Ibérico de Energia – Pólo Português
OTC	Over-The-Counter
PA	Environmental Remuneration
$\mathbf{P_A}$	Marginal price of area A
$\mathbf{P_B}$	Marginal price of area B
PF	Fixed Remuneration
Pi	Different order prices limits (1 to i)
PS	Previous Schedule

PSR	Production under Special Regime
PTRs	Physical Transmission Rights
PV	Variable Remuneration
PX	Power Exchange
$\mathbf{P_1}$	Last matched order price
$\mathbf{P_2}$	Penultimate matched order price
$\mathbf{QBuyers_A}$	Aggregated buyers quantity in area A
$\mathbf{QBuyers_B}$	Aggregated buyers quantity in area B
$\mathbf{QSellers_A}$	Aggregated sellers quantity in area A
$\mathbf{QSellers_B}$	Aggregated sellers quantity in area B
REE	Red Eléctrica de España
REN	Rede Eléctrica Nacional
RES	Renewable Energy Sources
$\mathbf{R_{ID}}$	Hourly revenue of the wind producer in the intraday situation
$\mathbf{R_{LL}}$	Hourly revenue of the wind producer in the lower limit situation
$\mathbf{R_{PSR}}$	Remuneration of the energy offered to the public grid by production under special regime
$\mathbf{R_{UL}}$	Hourly revenue of the wind producer in the upper limit situation
$\mathbf{R_{WP}}$	Revenue of the wind producer
SEN	Sistema Eléctrico Nacional
SO	System Operator
SP	Settlement Price
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TV	Tradable Volume
$\mathbf{TV_{PT}}$	Tradable Volume of the Portuguese area
$\mathbf{TV_{SP}}$	Tradable Volume of the Spanish area
TWh	Terawatt hours
UK	United Kingdom
UL	Upper Limit

USA	United States of America
VA	Volume to Assign
VAA	Volume Assigned to each Ask at EP
VAB	Volume Assigned to each Bid at EP
VM	Variation Margin
WF	Wind Farm
$\mathbf{YR_{ID}}$	Yearly Revenue of the wind producer in the Intraday situation
$\mathbf{YR_{LL}}$	Yearly Revenue of the wind producer in the Lower Limit situation
$\mathbf{YR_{UL}}$	Yearly Revenue of the wind producer in the Upper Limit situation
$\mathbf{YR_{UL2007}}$	Yearly Revenue of the wind producer in the Upper Limit situation in 2007
$\mathbf{YR_{UL2008}}$	Yearly Revenue of the wind producer in the Upper Limit situation in 2008
$\mathbf{YR_{UL2009}}$	Yearly Revenue of the wind producer in the Upper Limit situation in 2009
$\mathbf{YR_{25}}$	Yearly Revenue of the wind producer that derives from the IDS_{25}
$\mathbf{YR_{50}}$	Yearly Revenue of the wind producer that derives from the IDS_{50}
$\mathbf{YR_{75}}$	Yearly Revenue of the wind producer that derives from the IDS_{75}
$\mathbf{YR_{100}}$	Yearly Revenue of the wind producer that derives from the IDS_{100}
Z	Parameter that multiplies the environment remuneration, which differentiates the types of renewable energy sources

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1 Introduction

In this introductory chapter it will be presented the motivations that led to the execution of this thesis, alongside with the main objectives of the work.

1.1 Motivations

1973 oil crisis led to a global change in the European way of addressing energy issues. The impact suffered was so strong that European citizens had to learn how to cope with a totally new paradigm that modified even the cultural approach to energy problems. At the political level, the new paradigm imposed the need to reduce external dependence in energy supply. Thus, in striving to reach this objective, some priorities were defined: diversity of the oil supply, promote the saving and the rational use of energy and develop the endogenous sources of energy. In this context, renewable energy sources achieved a major role, as a main contribution to the global security in terms of energy supply.

Renewable energies have become a focus on today's society. This status was achieved due to the conjunction of two factors: the green credentials of renewables and the unsustainable scenario that is forecasted if the levels of production with origin in traditional fuel supplies are not reduced. Undeniably, the climate change concerns, coupled with high oil prices, peak oil[1], and increasing government support, are driving increasing renewable energy, incentives and commercialization, supported by favourable energy legislation.

It is widely recognised that generating electricity from fossil fuels is a polluting process whose carbon dioxide emissions provoke a highly negative impact on climate change. In fact, if we are to avoid the worst effects of climate change, the CO_2 emissions need to be halved, at least [1].

The rise in greenhouse gas emissions from energy is equally unsustainable. By 2030, global greenhouse gas emissions could more than double due to the rising use of fossil fuels, notably in developing countries [1].

In an economical perspective, electricity generated from fossil fuels is also unsustainable. In the European scenario, for instance, by 2030, oil imports are predicted to rise from 76% to 88% and gas imports from 50% to 81%, compared to the year 2000. Europe's import vulnerability puts an unsustainable stranglehold on its economy. According to the European Commission, for every $20 increase in the price of oil, the cost of Europe's gas imports alone rises by €15 billion annually, given the unfortunate link between oil and gas prices. The increase of oil prices over the past few years from $20 to $120 has added €75 billion to the EU annual gas import bill [1].

Renewable Targets

There is an urgent need for a long-lasting solution that is environmentally benign and economically sound; a solution that can be put quickly and efficiently into place. Renewable energies fill all of these criteria.

Up to now, an important factor behind the growth of the European wind market has been strong policy support both at the EU and the national level. The EU's Renewables Directive (77/2001/EC) has been in place since 2001. The EU aimed to increase the share of electricity produced from renewable energy sources (RES) in the

[1] Peak oil is the point in time when the maximum rate of global petroleum extraction is reached, after which the rate of production enters terminal decline.

EU to 21% by 2010 (up from 15.2% in 2001), thus helping the EU reach the RES target of overall energy consumption of 12% by 2010 [2].

In December 2008, though, it was established the future EU legislative framework for renewable energies. The European Union agreed a new Renewable Energy Directive to implement the pledge made in March 2007 by the EU leaders for a binding target of 20% of its final energy demand coming from renewable sources in 2020. This directive is a concrete step towards a sustainable energy future. The EU's overall 20% renewable energy target for 2020 has been divided into legally binding targets for the 27 Member States, averaging out at 20 %. In terms of electricity consumption, according to the European Commission, renewables should provide about 35% of the EU's power by 2020. With ambitious legislation, wind energy could provide 12-14% of Europe's electricity by 2020, a significant contribution to the binding target – more than a third of all the power coming from renewables [2].

The European Wind Energy Association reports that the Commission's goal of 12-14% of electricity from wind energy is achievable. 180 GW of installed wind capacity is needed to meet the 12-14% electricity. In 2008, wind power capacity in the EU increased by over 8.4 GW to reach a total of 65 GW. On average, wind power capacity needs to increase by 9.6 GW per year, approximately, over the next 12 years to reach 180 GW by 2020, so this is a target that can be reached with only a small increase in annual installed capacity growth.

Wind energy growth

In another record year for new installations, global wind energy capacity surged by 28.8% in 2008. The USA passed Germany to become the number one market in wind power, and China's total capacity doubled for the fourth year in a row.

The world's total installed capacity reached 120.8 GW at the end of 2008, over 27 GW of which came online in 2008 alone, representing a 36% growth rate in the annual market. Figure 1.1 illustrates the expansion of wind power in the world since 1996.

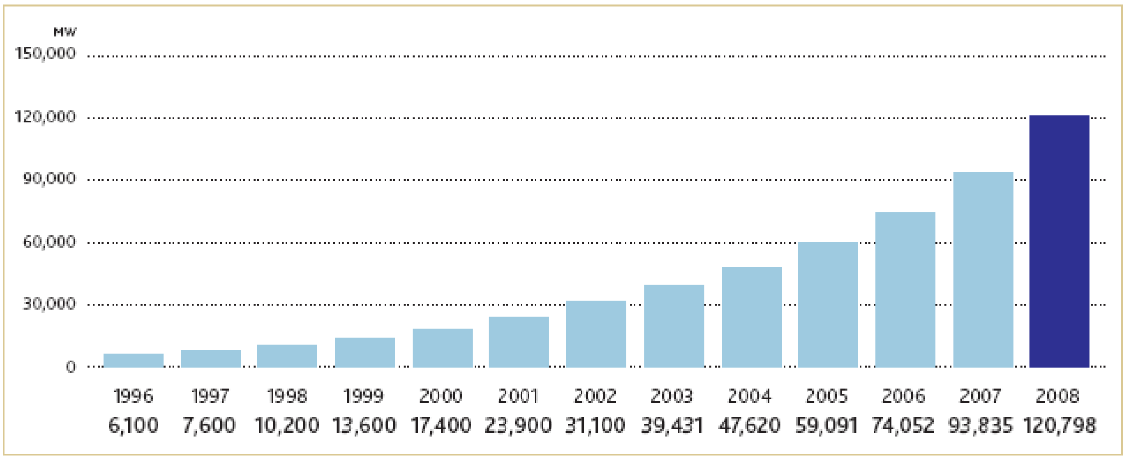
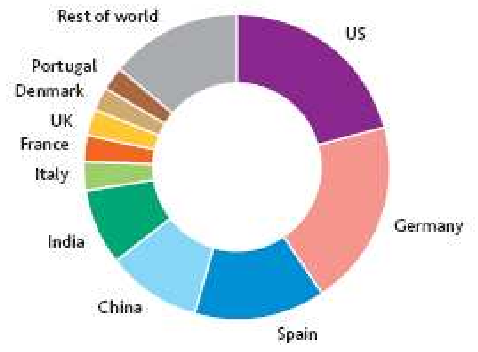
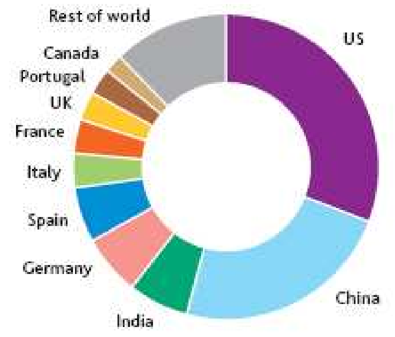


Figure 1.1 – Global cumulative installed capacity 1996-2008 [2].

Figures 1.2 and 1.3 show the top 10 nations in both total installed capacity and new capacity in 2008.



	MW	%
USA	25,170	20.8
Germany	23,903	19.8
Spain	16,754	13.9
China	12,210	10.1
India	9,645	8.0
Italy	3,736	3.1
France	3,404	2.8
UK	3,241	2.7
Denmark	3,180	2.6
Portugal	2,862	2.4
Rest of world	16,693	13.8
Total top 10	**104,104**	**86.2**
World total	**120,798**	**100.0**



	MW	%
USA	8,358	30.9
China	6,300	23.3
India	1,800	6.7
Germany	1,665	6.2
Spain	1,609	5.9
Italy	1,010	3.7
France	950	3.5
UK	836	3.1
Portugal	712	2.6
Canada	526	1.9
Rest of world	3,285	12.2
Total top 10	**23,766**	**87.8**
World total	**27,051**	**100.0**

Figure 1.2 – Top 10 total installed capacity in 2008 [2]. Figure 1.3 – Top 10 new capacity in 2008 [2].

In relation to Europe, wind power is now the fastest growing power generation technology. Indeed, more than 35% of all new energy installations in 2008 were wind power, which meant that renewable energy accounted for more than half of all new power generation capacity in the EU. A total of 23.851 GW of new power capacity was constructed in the EU last year. Out of this, 8.484 GW (36%) was wind power, 6.932 GW (29%) gas, 4.200 GW (18%) Photovoltaic, 2.495 GW (10%) oil, 762 MW (3%) coal, 473 MW (2%) hydro and 60 MW (0.3%) nuclear power capacity [1].

In the end of 2008, the European Union maintained its position, inherited from 2007, as the world's leader in total installed wind energy capacity, and one of the strongest regions for new development, with over 8.4 GW of new installed capacity. Industry statistics compiled by the European Wind Energy Association (EWEA) show that cumulative wind capacity increased by 15% to reach a level of 64.935 GW, up from 56.517 GW at the end of 2007 (Figure 1.4).

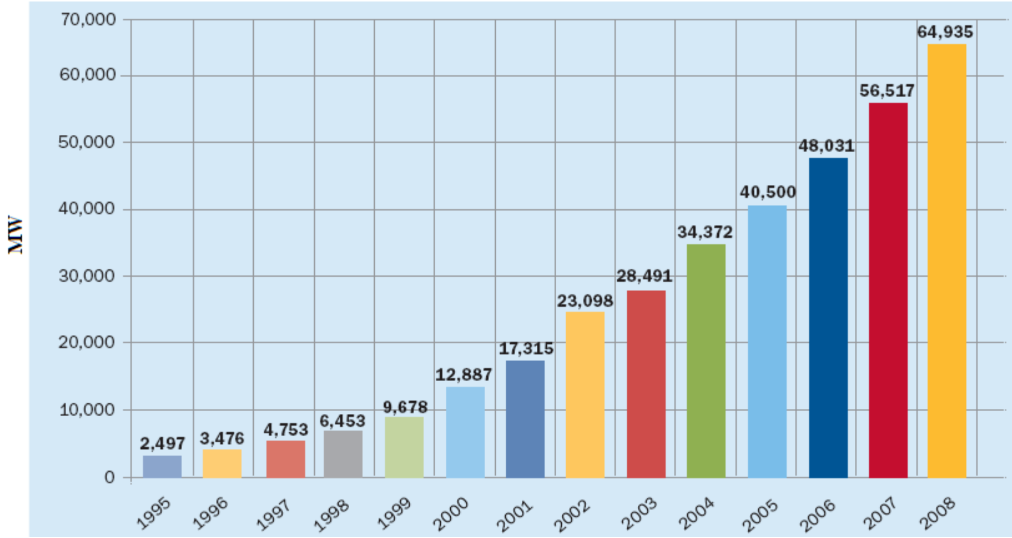


Figure 1.4 – Cumulative wind energy installations in Europe [1].

2008 saw a much more balanced expansion of the European wind market, relying less and less on the traditional wind markets of Germany, Spain and Denmark. There was a clearly second wave led by Italy, France, Portugal and the UK.

Germany was still Europe's leader in installed wind power capacity, with a total of 23.9 GW. Spain was Europe's second largest market, and has seen growth in line with previous years. In 2008, 1.6 GW of new generating equipment was added to the Spanish wind fleet, bringing the total up to 16.8 GW. At this rate of development, Spain is likely to reach the government's 2010 target of 20 GW of installed wind capacity. In 2008, wind energy generated more than 31 TWh, covering more than 11% of the country's electricity demand.

Italy brought its total installed capacity up to 3.7 GW, experiencing a significant leap in wind power capacity with over 1GW of new wind turbines coming on line in 2008. France continued its steady process of wind energy expansion. At the end of 2008, the total installed capacity stood at 3.4 GW, representing an annual growth rate of 38%. It is worthy mention that in 2008, around 60% of all new power generation capacity in France was wind energy [2].

It is also relevant to mention that the new EU Member States had their strongest year ever regarding wind power, in what can be seen as a distinct third wave. Hungary doubled its capacity to 127 MW and Bulgaria tripled its capacity from 57 MW to 158 MW. Poland, in the end of 2008, had 472 MW of installed wind power, up from 276 MW at the end of 2007. Additionally, it is worth mentioning that Austria and Greece are just below the 1 GW mark [2].

The advantages of wind energy

Wind energy is an indigenous and virtually unlimited energy source. Furthermore, it emits no greenhouse gases and does not deplete natural resources in the way that fossils fuels do. It also does not cause environmental damage through resource extraction, transportation or waste management. It even operates without water consumption and can be deployed in sites where there is a shortage of this resource.

Wind energy generates economic growth, providing income, wealth and technological leadership in Europe. Besides, it is also a labour-intensive power source which engenders employment. By the end of 2008, according to the EWEA, a total of 150,000 workers were employed directly and indirectly in the wind energy sector.

Moreover, wind energy replaces fossil fuel, and fossil fuel prices, which are a variable hard to predict. For instance, oil and gas prices have tripled since 2001, and in April 2008 the price of oil hit $120 a barrel. This inconsistency of fuel prices can act as drawback to economic development, once energy is essential for manufacturing most commodities and a main driver behind price formation: the three last global recessions have been triggered by oil prices rises. Consequently, the system will reduce the overall risk and cost to the economy by relying on a source that can be produced domestically and at predictable prices[2].

Additionally, the CO_2 savings that wind energy orders are of extreme importance if we are to avoid the worst impacts of climate change.

To sum up, wind energy is a flexible and multi-faceted solution that offers society concrete solutions in many fields. Not only can it help tackle the looming climate crisis, it can also make the EU's economy more competitive.

Wind energy limits

Due to the benign impacts in terms of harmful emissions inherent to renewables, it is undisputable that they should benefit from the support of both national and European Authorities. Within this context, one could question why, in the future, the investment should not be concentrated in renewable units. However, despite their green credentials, renewable units and, particularly, wind farms, have some drawbacks, mainly related with their integration in electricity grids.

As one may know, in the electricity system the generation must equal the consumption plus the losses at every moment, due to the incapacity of storing electricity at a large scale. Once the consumption pattern is highly variable in time, it is mandatory that the electricity system includes controllable power plants, capable of promoting the match between generation and consumption. Therefore, despite the inclusion of a significant percentage of renewable sources being highly desirable, we should bear in mind that the actual electricity system can not be operated based on a portfolio exclusively made of renewable sources, especially wind farms, since this resource is, by nature, uncontrollable.

In addition, another difficulty that should be highlighted is linked to the behaviour of the electricity system in the periods of low consumption and high hydro generation, frequently associated with a great availability of wind production. During those periods, wind energy and non controllable hydro energy are stored in the form of hydro energy in pumped storage plants, by elevating the water from a lower to a higher reservoir. In Portugal, new projected hydro power plants foresee the inclusion of this technique wherever it is applicable, according to the local geographical conditions. Even with such measure, there is no evidence that generation and consumption can be balanced without spoiling renewable resources. In the limit, it will be necessarily to cut renewable production, what is difficult to justify according to the energetic and environmental policies assumed.

[2] Variable costs are very low which means that the capital cost accounts for most of the costs that the investor will have to face during the life-time of the investment, and this is known at the time project starts.

Wind energy would benefit from real and effective power market competition

We are still a far cry from effective and fair competition in the European electricity markets. According to the European Commission, there are four key reasons why there is no competitive market: lack of cross-border transmission links; lack of adequate separation between production and transmission of electricity (so-called ownership unbundling); biased grid operators and low liquidity in wholesale electricity market. In order to remove some of these barriers, in May 2008, the European Parliament's Energy Committee voted in favour of full ownership unbundling, which is essential if just competition in the power market is to be attained.

According to the International Energy Agency, Europe needs to build more than 850 GW of new capacity in the period up to 2030, which is more than the capacity currently installed. Continued liberalisation and fair competition in the power market are certainly in the interests of the wind energy sector as they would expose investors to the risk of technology choice. Otherwise, inefficient competition means that, unless the companies making the investment decisions are exposed to the risk of unknown fuel and CO_2 costs, the electricity consumers will have to pick up the bill. Real competition can be a step forward to wind energy, once it would force investors in power units to value an energy that has neither CO_2 nor fuel costs.

Currently, there are some countries that have risen above the barriers and included, already, wind energy in the power market, namely Spain and Denmark. Portugal will follow this wind of change (as the feed-in remuneration method is reaching its end), in what should be a huge move to the continuous growth of wind energy and to the accomplishment of the target set by the European Commission. These two issues act as a motivation for the studying of the integration of wind energy in the Portuguese electricity wholesale market.

1.2 State of Art – Legal framework of wind energy in Europe

In this section it will be described the state of art of wind energy in Portugal, as well as the current remuneration process for wind producers. Furthermore, there is also allusion to the remuneration methods of three reference countries in Europe regarding wind power: Spain, Denmark and Germany.

1.2.1 Wind energy in Portugal

Portugal, having also suffered the consequences of the fossil fuels price increase, found it essential to follow the European Union politics in the use of internal sources of energy. The absence of energy sources as oil and gas and the forecasted extinction of coal in the Portuguese territory have opened a door regarding the development of alternative sources of electricity production, predominantly, promoting and encouraging the exploitation of indigenous and unlimited energy resources.

Not soon did wind energy started developing, mainly due to the ignorance of the wind potential of our country. The development of renewable resources started from hydropower, as the country had experienced decades in building and operating large hydro plants and, as such, the technology associated to it was considerably more mature than any other natural source. Wind came afterwards, and since then it suffered a breathtaking evolution, principally owing to the following measures:

- The rearrangement of the Portuguese electrical sector, started in 1995 and reinforced in 2006, which embraced competition in the wholesale power market. Subsequently, this marked the ending of the monopoly situation out of the incumbent company, EDP.
- The publication of numerous and relevant specific legislation concerning the promotion and development of renewables, namely the Decree Laws nº 189/88, nº 168/99, nº 312/2001, nº 339-C/2001, nº 33-A/2005 and nº 225/2007 which set the administrative framework for the activity in Portugal and in particular the economic conditions, namely remuneration, applicable to wind generation.
- The approval of the Renewable Directive, which estimates the setting up of 5 GW of wind turbines until 2012 in Portugal.
- A strong political commitment of the Portuguese Governments in promoting the development of renewable energies, since the last decade of the last century [3].

Figure 1.5 illustrates the evolution of the wind power installed capacity in Portugal.

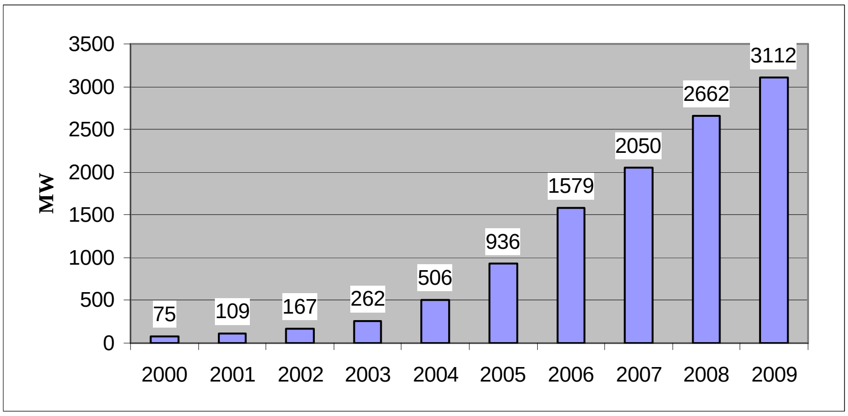


Figure 1.5 – Cumulative installed wind power in Portugal since 2000[3] [REN].

By the end of 2008, 1500 wind turbines were functioning in 173 wind farms. The wind power connected to the grid represented approximately 18% of the total installed capacity in the National Electricity System (SEN – Sistema Eléctrico Nacional), in the end of 2008 [4].

Figure 1.6 shows the energy produced with origin in the wind resource since 2000.

[3] The values of 2009 concern only the first six months.

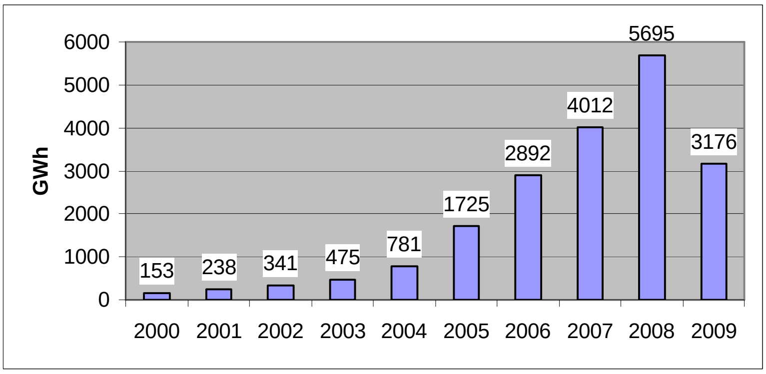


Figure 1.6 – Wind energy production in Portugal since 2000[4] [REN].

In 2008, the wind production increased 42% in relation with 2007, achieving a total of 5.7 TWh, which represents 11% of the total energy consumption of the SEN, or 14% of the total injected production in the public grid. In the first six months of 2009, the wind production has risen 15% in comparison with the homologous period of 2008. This production allowed supplying 13% of the national consumption.

The utilization of the installed wind capacity, in 2008, was 27% [4].

Remuneration process for renewable energies in Portugal

The production under a special regime (PSR)[5], i.e. production that uses renewable resources as primary energy, has benefited from several incentives, since its environmental impact is less than the "classic" generation models. These incentives apply to the obligation of purchasing the electric energy produced, within a previously defined remuneration process.

Decree-Law number 168/99 introduced profound alterations to the remuneration process of the energy produced by the PSR. Since then, it was successively actualized until 2007, when the last revision regarding the criteria of the remuneration method was published in the Decree-Law number 225/2007. This Decree defines the expression that allows determining the remuneration of the energy offered to the public grid by the PSR, the so-called feed-in tariff, as (1.1) [5]:

$$R_{PSR} = [k_{pt} \times (PF + PV) + PA \times Z] \times K_P \times K_{IPC} \tag{1.1}$$

where:

R_{PSR} (€/month) is the monthly remuneration applicable to the PSR;

PF is the fixed remuneration, which represents the avoided investment costs;

PV is the variable remuneration, which represents the avoided operation costs;

PA is the environmental remuneration, that valorises the avoided emissions of CO_2;

K_p is a parameter that books the losses prevented;

K_{IPC} is a correction according to the inflation, which is measured by means of the Prices to the Consumers Coefficient;

[4] The values of 2009 concern only the first six months.
[5] In Portugal, Combined Heat and Power (CHP) generation is also included in the PSR regime.

k_{pt} is a correction that depends on the diagram of energy production;

Z is a parameter that multiplies the environmental remuneration, which differentiates the types of renewable energy sources.

It this same Decree-Law is also defined the validity of this remuneration method, which depends on the technology. In the case of wind energy, the feed-in tariff is applicable to the first 33 GWh/MW injected in the grid or 15 years of installed power, which of the two occurs first.

Still, renewable producers are deeply concerned regarding what will follow the ending of the feed-in tariff. However, in the annex of the Decree-Law number 225/2007 [6] it is clearly stated that, once the limit is achieved, renewable energy units will be remunerated by selling their energy at market prices and for the selling of green certificates. In this thesis we will focus on the introduction of wind generation in the wholesale market.

1.2.2 Spanish remuneration process on wind energy

Spain is a worldwide reference when it comes to wind energy. After being the pioneer in wind power grid integration, Spain was also one of the first nations to include wind energy in the power market.

According to the Royal Decree 661/2007, new wind farms, with the definitive certificate for setting up installation subsequent to January, 1 2008, have two possible retributive options:

a) To sell the wind energy at a fix regulated tariff, the same one for all time periods;

b) To bid in the organised market, through the system of auctions managed by the market operator, MO, to establish a bilateral contract, or a forward contract.

Opting for option a), the wind producer communicates the day-ahead schedule to the distributor. The auction system managed by the market operator considers this schedule as a selling order at null price. It is important to underline that the schedule can be communicated directly, by the wind producer, or through a representative. In this option, the wind producer is also granted permission to participate in the intraday market. In terms of payment, the wind power producer is reimbursed by:

- The market operator for the amount that corresponds to daily and intraday market;
- The system operator by the amount that corresponds to the ancillary services and deviations;
- The Energy Regulatory Commission for the rest of the fix price of the tariff, in case the market price is lower than the regulated tariff. If the opposite situation is verified, it is the wind producer who has to pay the Energy Regulatory Commission.

The retribution for wind farms based on the regulated tariff can be summarized as (1.2).

$$Retribution_{RegTariff} = regulatedtariff \pm deviations + complements \text{ [6]} \qquad (1.2)$$

In option b), the wind producer sends the selling orders for the day-ahead market to the market operator. Participation in the intraday market is also allowed. All installations regardless of installed capacity receive a variable premium depending on the reference market prices. There are also a cap and a floor for the sum of the reference market price and the premium during the first 20 years of the installation. This cap and floor act as an upper and lower limit to the remuneration of the wind producer. As a matter of fact, if the market price plus the

[6] Complements: reactive power and voltage dips.

premium is below the lower limit, this limit will be received [7]. On the opposite, if the sum of the market price and the premium exceeds the upper limit, this limit will be received[7]. Figure 1.7 clarifies this procedure.

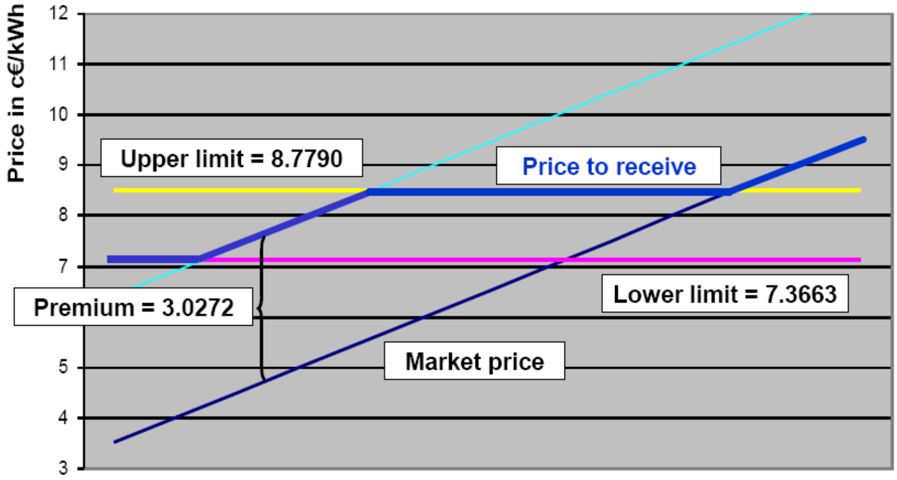


Figure 1.7 – Lower and upper price limits to be perceived by wind facilities [8].[8]

In this remuneration option, the wind producer is paid by:

- The market operator for the amount that corresponds to daily and intraday market;
- The system operator by the amount that corresponds to the ancillary services and deviations;
- The Energy Regulatory Commission for the premium.

Equation (1.3) emphasizes the different terms in this remunerative option.

$$Retribution_{Market} = marketprice + premium \pm deviations + complements^{9} \tag{1.3}$$

To sum up, what diverges in both remuneration options is basically the financial settlement of the Energy Regulatory Commission. The wind power producers will opt for one or another, depending on their risk management strategies.

1.2.3 Danish wind energy remuneration process

Denmark is also a pioneer regarding wind energy and it is worthy studying the remuneration process that is carried out in this particular country. Until 1999, the power produced by wind farms was purchased at 85% of the domestic tariff plus a government subsidy, at a total feed-in tariff of approximately 80 €/MWh. In 2000, though, this feed-in tariff was reduced to 60 €/MWh. In 2003, wind energy was launched in the Danish power market, the NordPool.

In 2008 new economic incentives for wind turbines onshore were introduced. This involved an innovative remuneration method, based on market price plus 30 €/MWh for the first 22000 full load hours[10]. There is also a 4 €/MWh compensation for balancing expenses. Besides this newly incentive methodology, it was also created a

[7] The cap only applies to a band of the market price. For high market price values, the generators receive the market price, which may exceed the cap.
[8] Prices with reference to October 2008.
[9] Complements: reactive power and voltage dips.
[10] Aproximately 9 years.

Green Fund, which receives a small state subsidy per kWh produced by each wind turbine for the first 22000 full load hours. This Fund has the goal of providing subsidies to initiatives that promote local acceptance of installation of wind turbines. Last but not least, another relevant issue in this 2008 law is the possibility for compensation to neighbours for devaluation of property due to building of wind turbines in vicinity. Consequently, wind power developers must offer a minimum of 20% ownership share to local residents [9].

1.2.4 German wind energy remuneration process

In Germany, an early feed-in law for wind-generated electricity has existed since 1991. The Renewable Energy Sources (Erneuerbare-Energien-Gesetz-EEG) came into force in 2000 and still provides the main stimulus for the German wind market. The EEG is regularly amended to adapt tariffs to current market conditions and new technological developments. The most recent amendment took place in 2008 with new tariffs and regulations which took effect on 1 January 2009.

Under the EEG, electricity produced from renewable energy sources is given priority for grid connection, grid access in both distribution and transmission grids, and power dispatch. The EEG stipulates a fixed feed-in tariff for each kWh of power produced and fed into the grid from renewable sources. For wind energy an 'initial tariff' is fixed for at least five and up to 20 years. It is then reduced to a 'basic tariff' depending on how local wind conditions compare to a 'reference yield'. For instance, wind installations on very good sites receive the initial tariff for five years, while turbines on lesser sites can extend the period. The tariffs are paid for 20 years.

As of 1 January 2009 the initial tariff for onshore wind energy was increased to 9.2 c€/kWh. This initial tariff will be reduced by 1% per year for new installations, i.e. projects which become operational in 2010 will receive an initial tariff of 9.2 c€/kWh – 1%. The basic tariff is set at 5.02 c€/kWh. It is important to mention that there is a different tariff regarding the offshore wind energy.

Grid operators are obliged to feed-in electricity produced from renewable energy and buy it at a fixed price within their supply area. Furthermore, the new EEG requires that grid operators not only extend the grid, but also that they optimise and enhance the existing grid [2].

1.3 Thesis objectives/ Structure

The purpose of this thesis is to forecast the incorporation of wind energy, in Portugal, in a competitive wholesale market. Specifically, it is intended to carry on a set of simulating studies in order to draw some conclusions regarding the impact on the revenue of Portuguese wind energy producers coming from their integration in a competitive electricity market. To accomplish this goal, though, it is necessary to study the electricity market in which Portugal is included, the Iberian Electricity Market, MIBEL. Effectively, analysing the functioning of MIBEL is also the focus of this thesis, as it is the platform for the inclusion of wind energy in the power market. The inspection of the Iberian Electricity Market has two strands: one theoretical, in which is presented the main features of MIBEL, and other practical, regarding the development of a market simulator.

Chapter two offers a global overview of the operation of electricity power markets. It starts by describing the Portuguese electricity system as well as the entities responsible for each vital activity: generation, transmission, distribution, supply, regulation, market operation and system operation. The Iberian Electricity Market is also scrutinized in this chapter, taking into account its interconnected bipolar structure where the day and intraday markets are under the supervision of the Spanish division, OMEL, and the organised derivatives market is under the responsibility of the Portuguese division, OMIP. The operation of the day-ahead and the intraday markets is object of a detailed explanation in this chapter.

The third chapter explains both the algorithm used to implement the market simulator and the model established for assessing wind energy revenue in MIBEL's power market. The description of the algorithm used to simulate the effective functioning of MIBEL is introduced by a reference to the congestion management methods and, specifically, Market Splitting as it is the model used by Portugal and Spain to allocate interconnection capacity in the day-ahead timeframe. The methodology employed to compute the introduction of wind energy in the power market is divided in four main topics: strategy, which describes the relation of wind farms with the different markets of MIBEL, generation forecasts, where are referred the two methods brought into play to estimate the wind production (ARMA and NWP), implementation, which explains the overall algorithm and assumptions, reporting the hypothesis adopted in the algorithm.

Chapter four presents the results of the simulations carried out in this thesis as well as the conditions under which they were performed. The different case studies are portrayed. Furthermore, central aspects of the work will be discussed based on the outcome of the simulations, namely the liquidity of the intraday market, the relation of the quality of the wind forecast with the financial income of wind producers and the preponderance of the deviations' prices.

Last but not least, in chapter five the main conclusions of the work are presented, alongside with a reference to further studies and evaluations that are welcome to reach important developments not only in the wind energy theme, but also in the renewables scenario.

2 Market concepts – The Iberian Electricity Market

In this chapter it will be characterized the Portuguese electricity system, with particular focus to the entities that play key roles on it. Furthermore, the Iberian Electricity Market, MIBEL (Mercado Ibérico de Electricidade), is also analysed in this chapter, taking into particular consideration the day-ahead and the intraday markets.

2.1 Electricity market core components

The goal of electricity market liberalisation is to create benefits by introducing incentives for higher efficiency and more innovation. Effective incentives are created by introducing competition between market players. Competition exposes market players to the risk of losing market share, or even going bankrupt, if they are not sufficiently efficient and innovative. But it also provides rewards for taking risks and performing better than one's competitors.

The liberalization process has brought to the power trading community culture, skills, processes, products and systems that have been widely used in more developed markets, together with experienced resources. In particular, there is a significant trend to implement, mutatis mutandis, the models that have proven to be efficient in other commodities and securities markets, for trading, clearing, products, risk-management tools, business models, supervision, amongst others.

However, electricity is a special commodity that needs specific provisions to be taken when designing a market, which derive from electricity physics fundamentals, namely:

- Non storability (at least in the context of wholesale market);
- Physical flows that follow physical rules and not contractual paths;
- Low dynamic performance of generation;
- Low elasticity of demand.

Those characteristics have led to a widespread market model, commonly adopted in countries that have undertaken a liberalization process, which includes the main components illustrated in Figure 2.1.

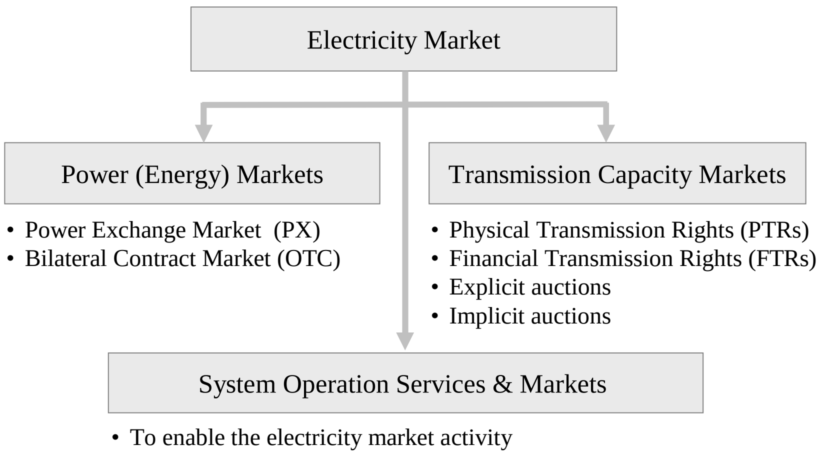


Figure 2.1 – Electricity market main fundamental components.

2.2 The Portuguese electricity system

Before we dive into the characterization of MIBEL it is relevant to introduce the Portuguese electricity system, as well as the types of companies and organizations that play a role in it.

2.2.1 Electricity value chain in Portugal

The electricity industry in Portugal can be divided in five main activities, each one carried out by different entities: generation, transmission, distribution, supply and operation of the regulated electricity market.

Starting from the top of the chain, generating companies produce and sell electrical energy using different technologies and primary energy sources (coal, gas, diesel, fuel, water, wind, biomass, solar, amongst others). In Portugal, electricity generation is totally opened to competition, subject to obtaining the requisite licenses and approvals. Electricity generation is divided in two regimes: ordinary generation regime, which refers to the generation of electricity through traditional non-renewable sources and large hydro-electric plants, and production under special regime (PSR), which refers to the use of alternative indigenous and renewable sources for electricity generation and for cogeneration. Generating companies may also sell services such as regulation, voltage control and reserve that the system operator needs to maintain the quality and security of the electricity supply. In the actual legal paradigm, the ideal of a centralized electricity generation planning is replaced by a market and private incentive philosophy. In Portugal the principal generating companies are EDP Produção[11], Turbogás, Tejo Energia and EDIA (Empresa de Desenvolvimento de Infra-estruturas do Alqueva) [10].

Transmission system operation refers to the ownership and operation of transmission assets such as lines, cables, transformers and reactive compensation devices. This equipment connects production units to consumers and is operated according to the instructions of the system operator that is responsible for assuring the equilibrium between supply and demand. Electricity transmission activity is carried out through the national transmission grid, through an exclusive concession granted by the Portuguese state to REN[12] on June 15, 2007 for a 50 year period.

Electricity distribution companies distribute electricity received from the national transmission and distribution grids directly. In a traditional environment, they have a monopoly for the sale of electricity to all consumers connected to the network. In a fully deregulated environment, the sale of electricity to consumers is decoupled (unbundled) from the operation, maintenance and development of the distribution network. Independent retailers then compete to perform this activity, in a market environment. The national distribution grid is operated through an exclusive concession granted by the Portuguese state. Presently, the exclusive concession for the activity of electricity distribution in high and medium voltage has been awarded to EDP Distribuição. The low voltage distribution grids continue to be operated under concession agreements awarded by municipalities primarily to EDP Distribuição [10].

The supply of electricity is now fully open to competition, subject to obtaining the requisite licenses and approvals. Retailers are able to freely buy energy on the wholesale market and resell it to consumers who do not wish, or are not allowed, to participate in this wholesale market. They have the right of access to the

[11] Incumbent utility in Portugal.
[12] REN – Rede Eléctrica Nacional, SA.

transmission and distribution grids upon payment of access charges set by the regulator, ERSE[13]. Under the new electricity framework, consumers are free to choose their retailer, and may switch retailers without incurring any additional charges. A new entity, whose activity will be regulated by ERSE, will be created to oversee the logistics operations of switching retailers. Retailers are subject to certain service standards with respect to the quality and continuous supply of electricity and are required to provide access to information in simple and understandable terms. They are, above all, responsible for managing client relationships with costumers, including billing and costumer service. However, a regulated tariff regime is still available for all customers in Portugal, who are free to choose between the liberalized market and the regulated regime, which is operated by the biggest retailer in Portugal, EDP – Serviço Universal S.A.. This company plays the new role of the last resort supplier, which is subject to regulation by ERSE. The last resort supplier is responsible for the purchase of all electricity generated by special regime generators, an obligation which until January 1, 2007 was carried out by REN, and for the supply of electricity to costumers that purchase electricity under tariffs or regulated customers and is subject to universal service obligations. This competition between regulated tariffs and liberalized market is temporary, and provisions to limit the scope of application of last resort tariffs to small clients have been approved by the Portuguese and Spanish Governments under the framework of MIBEL. Within the liberalised market there are some companies that act as retailers as Iberdrola, Union Fenosa, Endesa and EDP Comercial.

Last but not least, the electricity market operation is an activity assigned to the market operator (MO). The MO is the agent that matches sale and purchase orders that sellers and buyers of electricity have submitted according to market rules that he has defined, typically through a computer system. It also takes care of the settlement of the matched orders. This means that it collects payments from buyers and forwards them to sellers following delivery of energy. The organized electricity markets operate on a free market basis, subject to authorizations jointly granted by the Minister of Finance and by the Minister responsible for the energy sector. In Portugal the entities responsible for this task are OMIP (derivatives market) and OMEL (day-ahead and intraday markets).

Figure 2.2 summarizes the electricity value chain in Portugal, including the companies responsible for each activity.

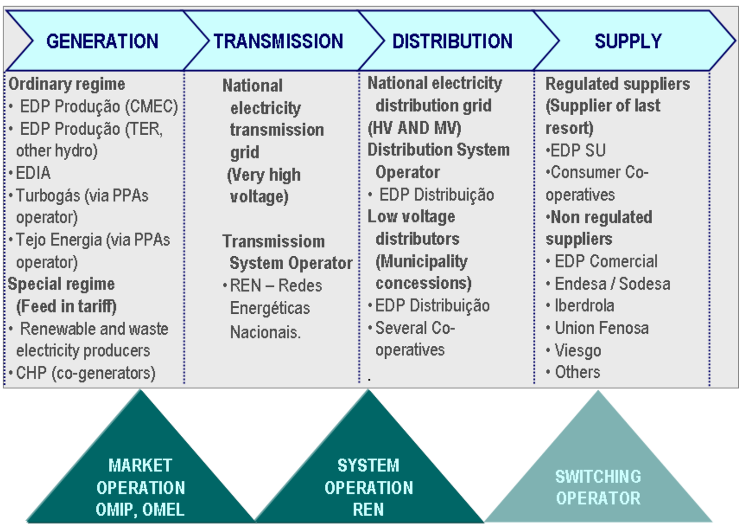


Figure 2.2 – Electricity value chain in Portugal [10].

2.2.2 Portuguese electricity market model

[13] The national regulation authority – ERSE (Entidade Reguladora dos Serviços Energéticos).

In order to reach a representation of the Portuguese electricity market model, let us introduce two more entities that play key roles in the electrical system.

The independent system operator (SO) has the primary responsibility of maintaining the security of the power system, thus enabling the market activity. It is called independent because in a competitive environment, the system must be operated in a manner that does not favour or penalize one market participant over another. The SO, role that in the case of Portugal has been assigned to REN, owns the computing and communications assets required to monitor and control the power system in order to carry out the required activities, in particular the balancing of generation and load in real time, voltage regulation, system restoration, etc..

The regulator, ERSE in the Portuguese paradigm, is the independent body responsible for ensuring the fair and efficient operation on the electricity sector. It determines or approves the codes that govern the electricity market and supervises the activity of the entities that operate in it. The regulator also sets the prices for the products and services that are provided under a monopoly regime.

Last but not the least; consumers are the goal of the electrical system. Small consumers typically buy electricity from a retailer and lease a connection to the power system from their local distribution company. Their participation in the electricity market usually amounts to no more than choosing one retailer amongst others, that will act as the sole interface between the consumer and the network and system services providers, namely for contracting connection to the grid and for regulated tariffs payment.. Large consumers, on the opposite, are more likely to take an active role in electricity markets by buying their electricity directly from the market. The largest consumers are sometimes connected directly to the transmission grid.

Having identified the main actors and relationships, we can now move forward to the representation of the Portuguese electricity market model.

Actually, Portugal has an electricity market model that includes two segments: the regulated and the liberalised. The regulated segment is the oldest one and is characterized by the absence of competition in retail business, as Figure 2.3 demonstrates.

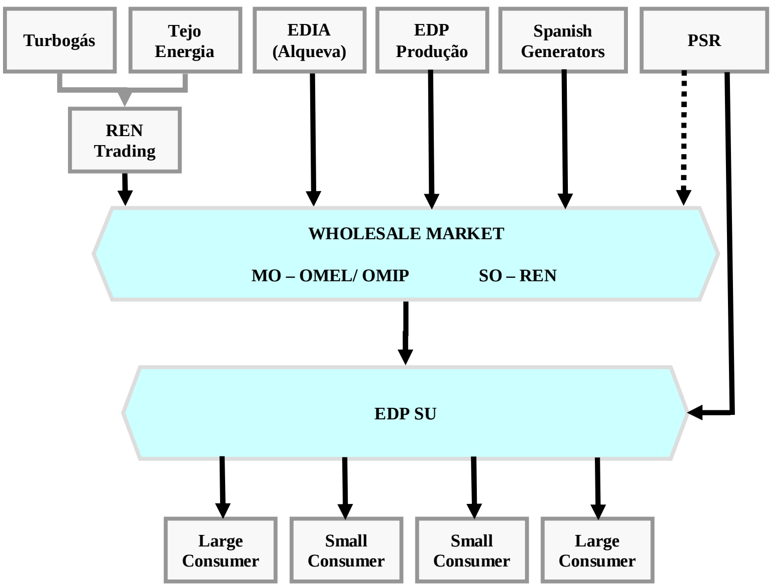
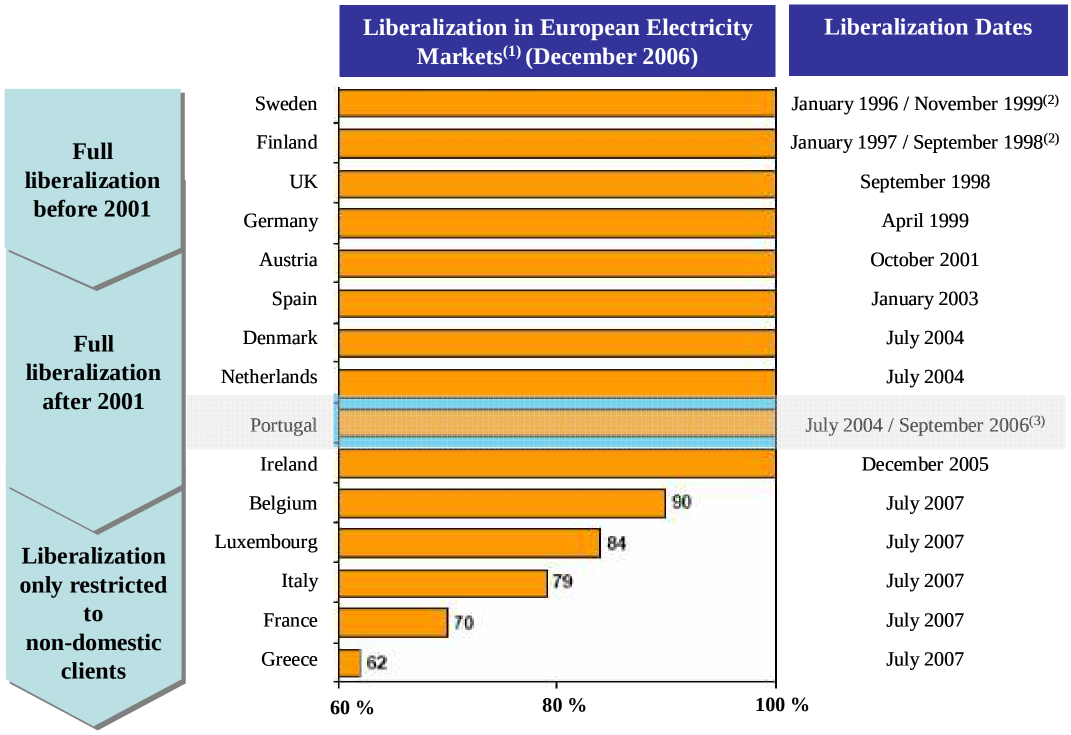


Figure 2.3 – Portuguese regulated market.

For long time the purchase of electricity under a regulated tariff regime was the only alternative for consumers in Portugal. Nevertheless, in this model they did not get the opportunity to choose their supplier as the retail business was monopolised by EDP Distribuição. Furthermore, clients were not allowed to establish bilateral contracts with generating companies and could not buy energy directly on the wholesale market.

However, following the changes towards liberalization operated in Germany, the UK, Spain, Austria and the Nordic countries in their own electricity market models, Portugal started implementing and designing another model and in 2004 came up with a much more competitive one, ahead of countries like Italy, Belgium or even France, as it can be witnessed in Figure 2.4.



(1) Percentage of eligible consumption relative to total consumption. (2) Although full liberalization was legally defined to happen in 1996 in Sweden and in 19977 in Finland, that only happened later when specific measures to facilitate domestic consumers switching were implemented. (3) Although full liberalization was legally included in the Decree-Law nº 192-2004, the effective right to choose electricity supplier for domestic consumers only started in September, 2006.

Figure 2.4 – Liberalization dates of different European's electricity markets [Portuguese Government].

Contrary to the regulated model, this new liberalised system allows consumers to choose their energy supplier, by introducing competition in the retail market. Besides, clients within this system can also establish bilateral contracts with generating companies. By introducing this new scenario, Portuguese authorities were focused in reaching a model that could induce competitive prices in this market segment. Figure 2.5 shows the Portuguese liberalised model, as well as the companies and organizations that play a key role in it and the interactions between them.

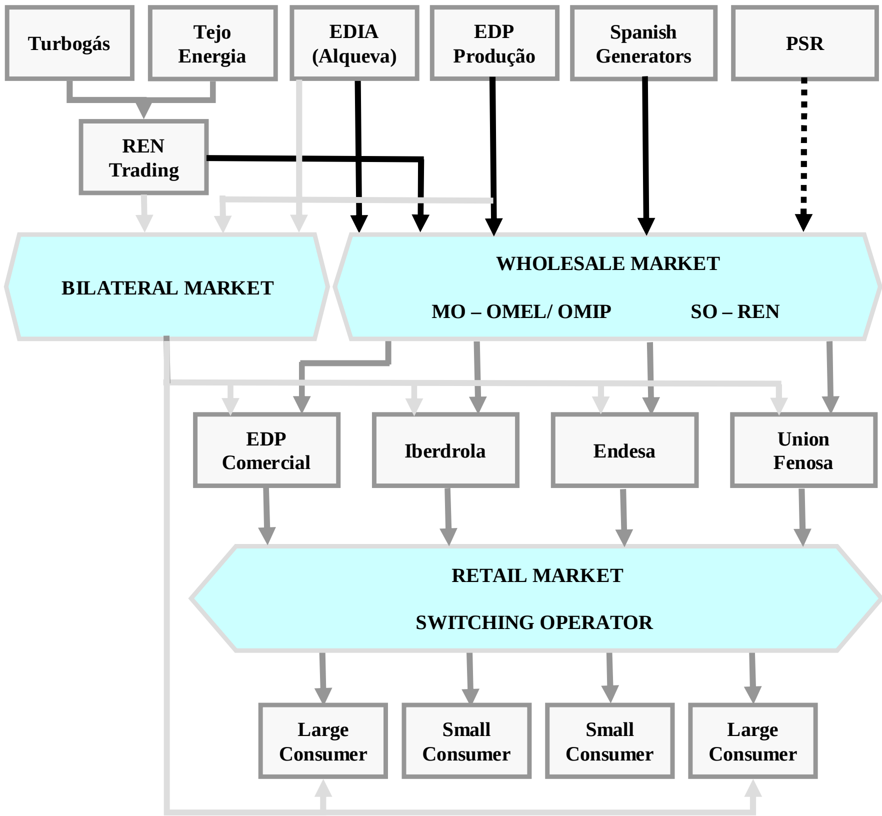


Figure 2.5 – Portuguese liberalized market.

Figure 2.5 illustrates that most small and medium consumers purchase energy from retailers, who in turn buy it in the wholesale market. Large consumers, though, are more likely to choose to purchase energy directly on the wholesale market or through bilateral contracts. In this model, the wholesale price is determined by the interplay of supply and demand. Due to all these factors, from an economics perspective, this model is the most satisfactory because energy prices are set through market interactions. Nevertheless, implementing this model requires considerable amounts of metering, communication and data processing.

Liberalised models such as the Portuguese one are defended by some economists to be the most effective one, as the introduction of competition implies an efficient market alternative to centralized control and coordinated planning. However, some still argue that a centralised and regulated structure would increase reliability and would be the best approach in cases where industry structure does not allow a truly competitive market model.

In Portugal, there was a wide acceptance of the liberalised model but some of its outcomes, namely competitive pressure on the wholesale and retail markets are still at an early stage.

2.3 MIBEL

The Iberian Electricity Market (Mercado Ibérico de Electricidade – MIBEL), is a joint initiative from the Portuguese and Spanish governments, and is a crucial step towards the development of the internal electricity market. With the materialisation of MIBEL, it becomes possible for any consumer in the Iberian zone to acquire electrical energy under a free competition regime, from any producer or retailer that acts either in Portugal or Spain.

The management of the organised markets of MIBEL is based on an interconnected bipolar structure, where the day and intraday markets are operated by the Spanish division (OMEL) and the organised derivatives market is under the responsibility of the Portuguese division (OMIP[14]). MIBEL entities, though, have permanent cooperation. For instance, if an agent was granted the status of producer, retailer or other, by one country, this would imply automatic recognition by the other country, granting equal rights and obligations to that agent.

MIBEL's main goals are:

- To benefit the electricity consumers of both countries, through the integration of the respective electric systems;
- To structure the market organization on the basis of principles of transparency, free competition, objectivity, liquidity, self-financing and self-organization;
- To support the development of the electricity market of both countries, with the existence of a single reference price for the whole of the Iberian Peninsula;
- To allow all the participants free access to the market, under equal conditions of rights and obligations, transparency and objectivity;
- To promote economic efficiency of electrical sector companies, encouraging free competition amongst them [11].

Besides OMIP and OMEL, there are many other locations of exchanges trading electricity, worldwide, as Figure 2.6 illustrates.

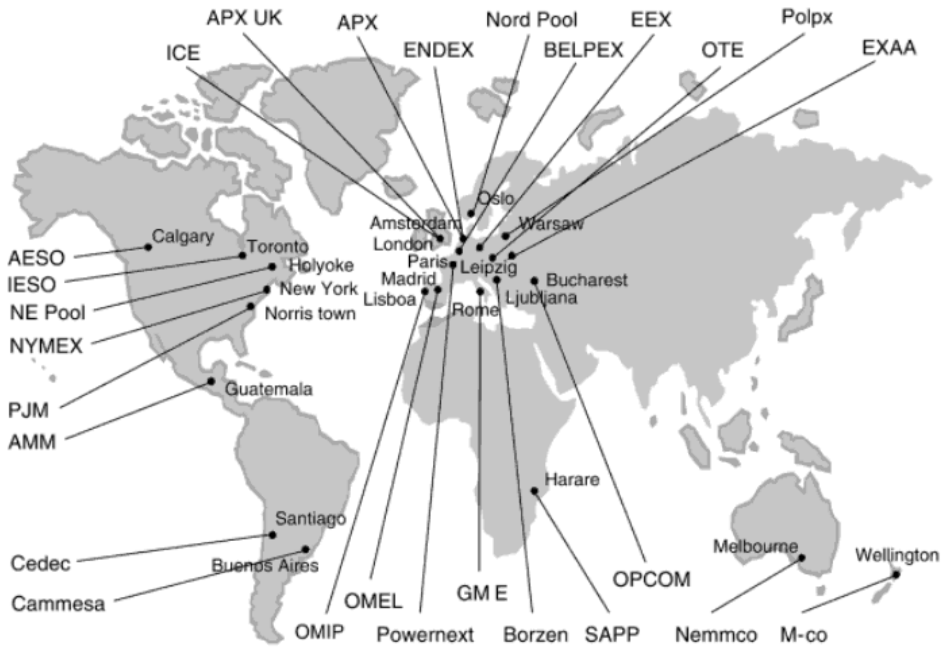


Figure 2.6 – Locations of exchanges trading electricity [12].

[14] The main features of OMIP are described in Appendix A.

2.3.1 Benefits of market integration

MIBEL is a regional approach of European electricity market integration. The economical benefits of such integration will be highlighted in this section.

Before diving into that economic analysis, though, it is important to have clearly minded the concepts of consumers' surplus, producers' surplus and social welfare. Figure 2.7 illustrates those concepts.

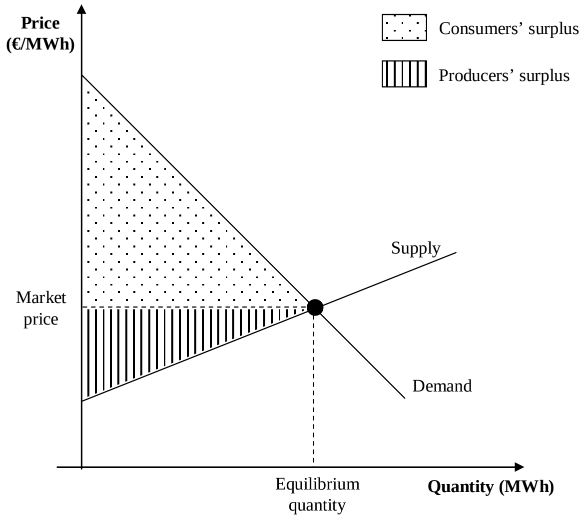


Figure 2.7 – Consumer surplus and producer surplus.

The producers' surplus arises from the fact that all goods, except for the marginal production, are traded at a price hat is higher than their opportunity cost. As Figure 2.7 shows, this surplus is equal to the area between the supply curve and the horizontal line at the market price. Producers with a low opportunity cost capture a proportionately larger share of the profit than those who have a higher opportunity cost.

On the opposite, the consumers' surplus represents the extra value that consumers get from being able to buy a commodity at a price higher than the market price. In other words, they will pay less than they were disposed to, so this corresponds to a gain in the consumers' perspective. The consumers' surplus can be determined, as illustrated in Figure 2.7, by the area between the demand curve and the horizontal line at the market price.

The social welfare, or total surplus, corresponds to the sum of the producer's and consumers' surpluses. At a national level, a well-functioning and competitive electricity wholesale market maximizes social welfare of the market as a whole. The lowest energy asks as well as the highest energy bids are satisfied first as long as bids and asks match. This results in producers' and consumers' surplus, Figure 2.7.

The congestion costs are the costs to society of having different prices in power markets. In other words, the congestion costs are the loss in social welfare due to congestion. The congestion costs can be measured using the net exporting curve (NEC). For a given hour, the NEC of each market is constructed from demand and supply curves of the market: for each price P there is a given demand for imports (excess domestic demand) or supply of exports (excess domestic supply). These quantities represent the difference between supply and demand corresponding to each price P. All in all, the NEC of a market gives, for each additional MW exported or imported by the market, the price that would be observed in this market, Figure 2.8.

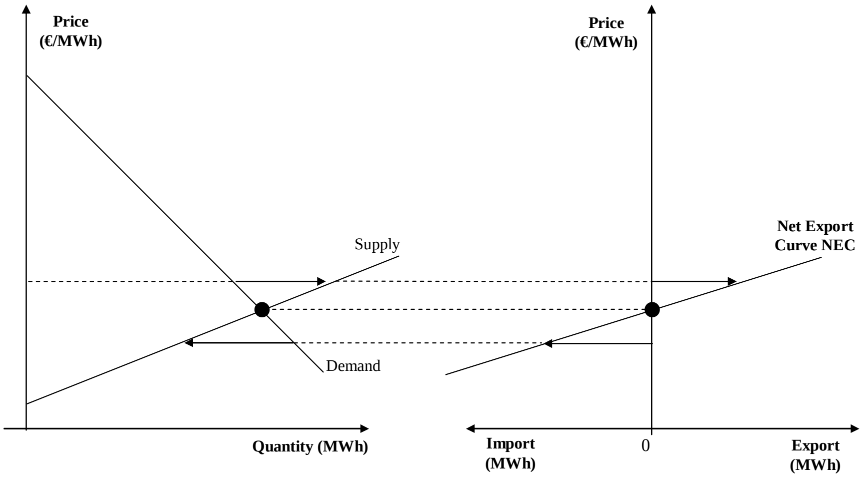


Figure 2.8 – Net Export Curve (NEC).

Coupling two markets is done easily using the NECs. The market with the lowest isolated marginal price exports to the market with the highest isolated marginal price. The export of one market is equal to the import of the other, thus the equilibrium is found at the intersection of the net exporting curve of a market, and the net importing curve of the other (the inverted NEC) [13]. Figure 2.9 illustrates in a single graph the NECs of two markets, A and B as well as the congestion costs.

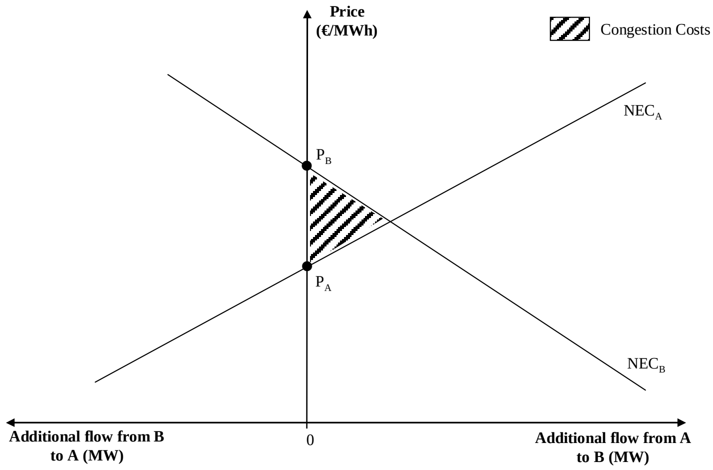


Figure 2.9 – NECs of two markets A and B and congestion costs.

Figure 2.9 denotes the importance of interconnection capacity availability: had sufficient interconnection capacity been available the market would have cleared at the intersection of NEC_A and NEC_B. As no sufficient interconnection capacity was available, the two separate markets cleared at P_A and P_B. The foregone surplus (congestion costs) is represented by the shaded area.

Figure 2.10 shows how maximizing cross-border capacities could decrease the congestion costs.

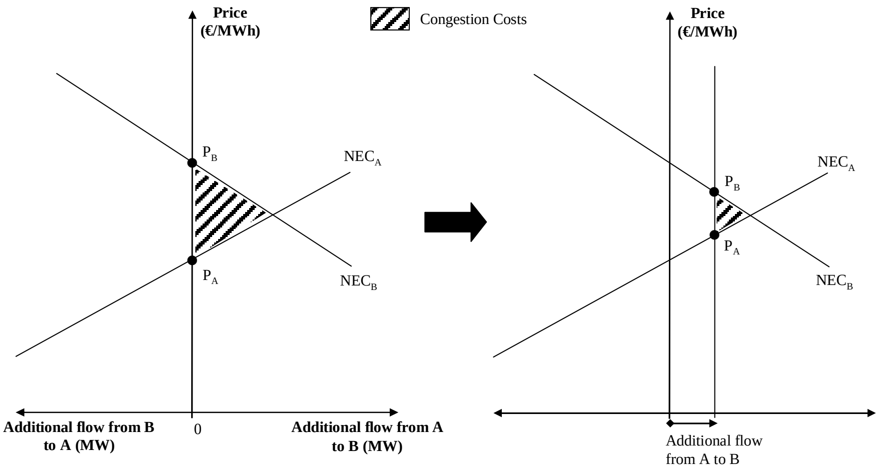


Figure 2.10 – Impact on the congestion costs of interconnection capacity maximization.

Moreover, let us know focus in the social welfare generated by cross-border flows. Considering the same markets, A and B, define P'_A and P'_B as the prices of markets A and B if they were isolated, i.e. if the cross-border flow between A and B was zero, and P_A and P_B the marginal prices of each market if there was a flow of power from A to B. Figure 2.11 schematizes the surpluses generated by the this cross-border flow.

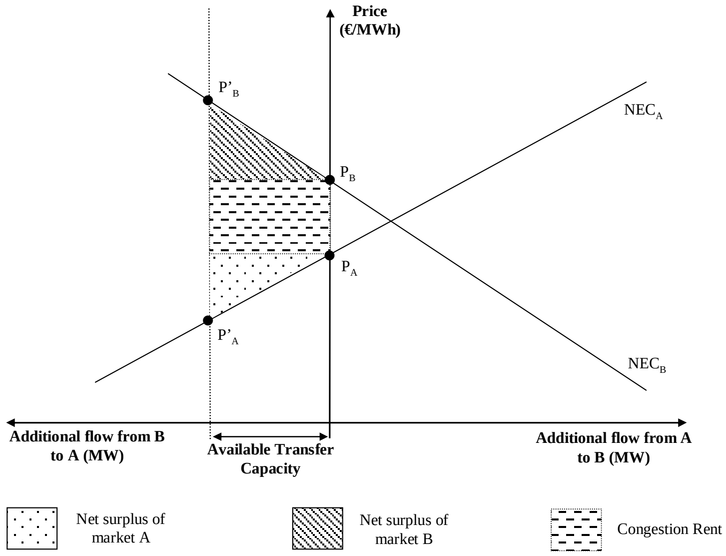


Figure 2.11 – Surpluses generated by a cross-border flow.

Figure 2.11 illustrates that the cross-border flow between A and B directly generates surplus for each market. Additionally, it generates a surplus for the transmission system operator (TSO), the congestion rent, which is used by the TSO for decreasing grid access tariffs, maintaining the existing cross-border capacity or investing in the grid.

Distribution of surplus generated by cross-border flows

Even if some market participants lose out, the consequence of a cross-border flow from a low-priced market to a high-priced market is always a net surplus in both markets A and B. This occurs because a larger part of high-price demand is satisfied by a larger part of low-price supply, due to the interconnection flow.

For instance, if market A is the exporting market, then an export from A is beneficial to producers in that area, while it is disadvantageous to its consumers. Consequently, the surplus of the consumers of market A will be lower when A is exporting than when it was isolated. On the other hand, the surplus of the producers of this area rises when market A exports. However, the difference between the increase in surplus for producers in market A and the decrease in surplus for consumers in market A is always positive. As a result, the net surplus for the market A in total is positive. This is shown in Figure 2.12.

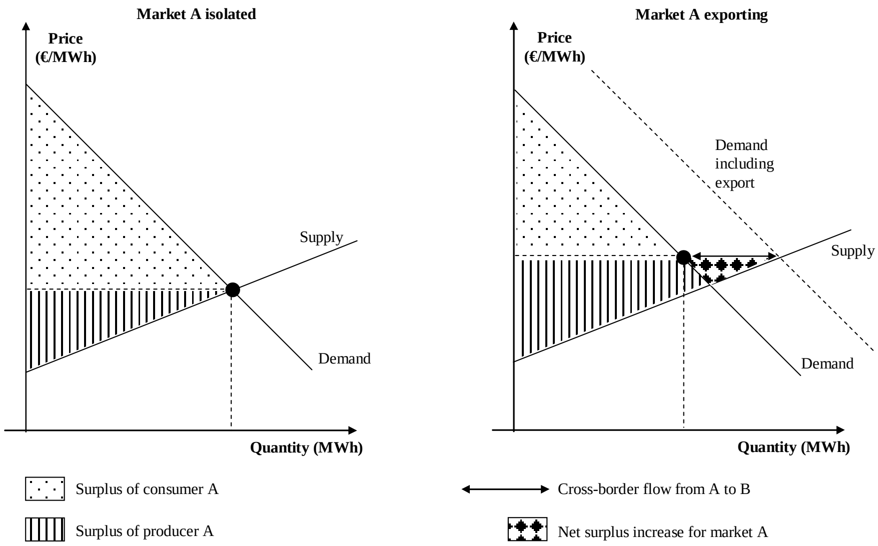


Figure 2.12 – Net surplus increase for the market A.

Figure 2.13 also demonstrates the net surplus increase for market A generated by an interconnection flow from A to B, but based on the NEC of market A.

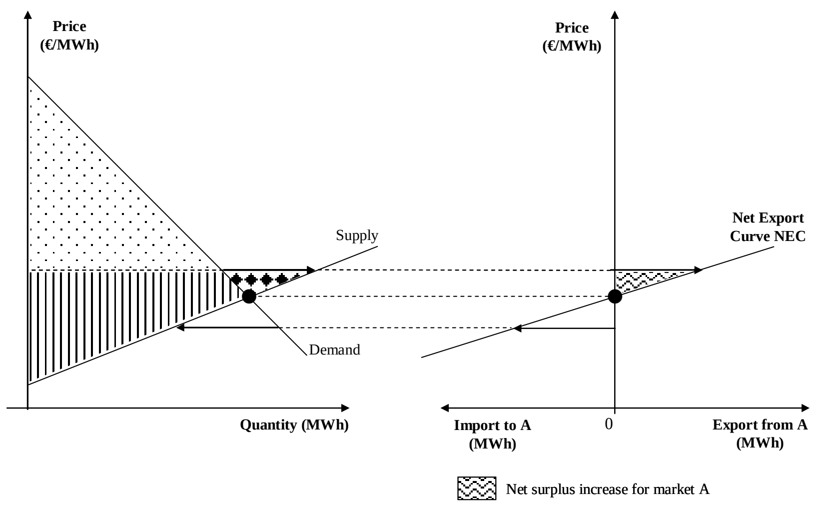


Figure 2.13 – Net surplus increase for the market A using the NEC.

Regarding market B, as it plays the role of the importing market, the symmetric situation will occur: an import to B reduces the surplus of producers in market B, while it is beneficial to consumers in market B. This can be considered as a transfer of surplus from producers to consumers of market B. Still, the difference between the increase in surplus for consumers in market B and the decline in surplus for producers in market B is always positive. Consequently, the net surplus for the market B as a whole is positive, as it can be seen in Figure 2.14.

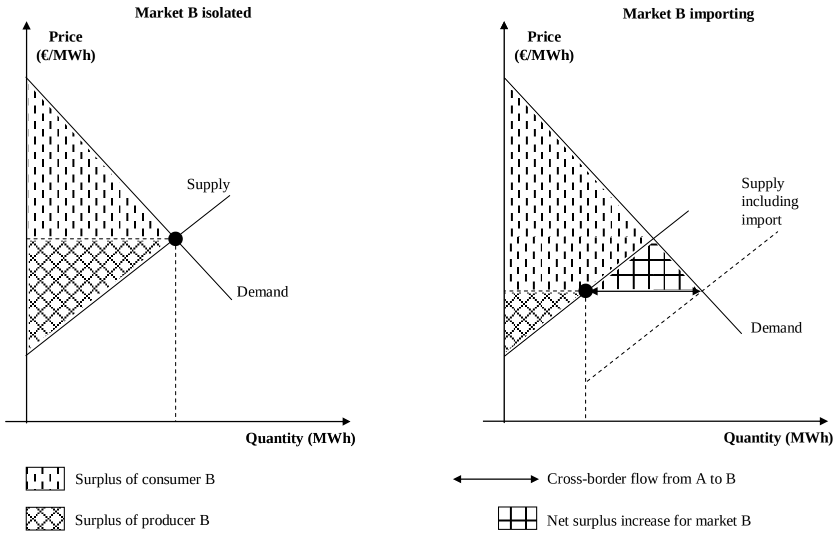


Figure 2.14 – Net surplus increase for the market B.

The net surplus increase for market B, generated by a cross-border flow from A to B, can also be schematized on the NEC of market B, as it is patent in Figure 2.15.

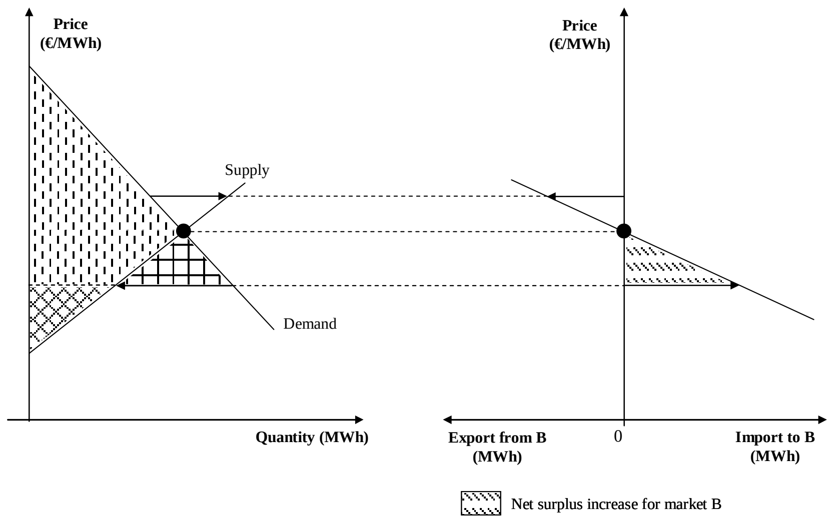


Figure 2.15 – Net surplus increase for the market B using the NEC.

Lastly, it should be mentioned that, at borders, where the price differential direction regularly changes, the winners and losers of cross-border flows change at the same time. When a market imports, its consumers win and raise their surplus, but when the flow direction switches the same consumers will lose. The opposite happens to producers.

2.3.2 MIBEL's day-ahead market (spot market[15])

The day-ahead market is managed by OMEL since January 1998. The purpose of the day-ahead market, as an integral part of electricity wholesale market, is to handle electricity transactions for the following day through the presentation of electricity sell and purchase orders by market participants [14].

Most transactions are carried out in the day-ahead market. All available production units must participate in this market, in case they are not bound by physical bilateral contracts, as well as external agents registered as sellers. Buyers on the daily market are last resort suppliers, retailers, qualified consumers and external agents registered as buyers. Selling orders (asks) made by producers are presented to the market operator, OMEL, and will be included in a matching procedure that will affect the daily programming schedule corresponding to the day after the deadline date for the reception of orders for the session, and comprising twenty-four consecutive programming hours (twenty-three or twenty-five periods on days which the clocks are changed). The deadline for the reception of orders by the market operator for day D+1 is 10:00 (CET) of day D. An example of that matching procedure, for one hourly period is patent on Figure 2.16.

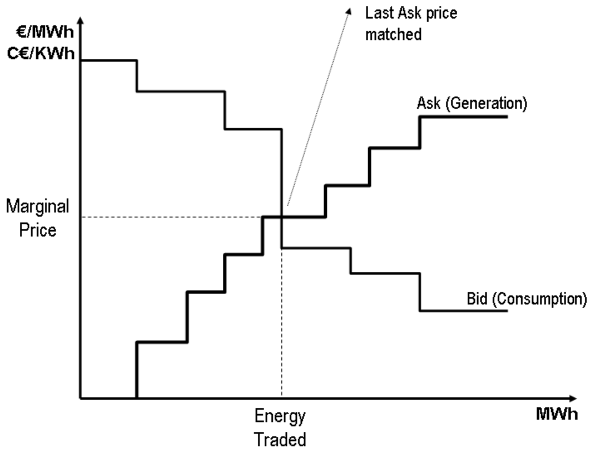


Figure 2.16 – Day-ahead market matching procedure diagram.

On MIBEL's day-ahead market, electricity sale orders presented to the market operator may be simple or incorporate complex conditions in terms of their content. Simple asks only specify a price and an amount of power. Complex asks are characterized by incorporate complex sale terms and conditions. The price in each hour will be equal to the price of the last block of the ask of the last production unit whose acceptance has been required in order to meet the demand that has been matched (Figure 2.16) [14].

The two main advantages of the day-ahead market are simplicity and immediacy. Furthermore, a producer is able to sell the exact quantity he has available and, on the other hand, a consumer can purchase the exact amount

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[15] The day-ahead market is also known as spot market. However, this denomination is not unanimous, as some authors affirm that the spot market includes both the day-ahead and the intraday markets. In this work we will avoid using the term "spot market" to clarify the reader. Nevertheless, whenever that term is used, mainly in Figures taken from foreign sources, it just concerns the day-ahead market.

he needs. Yet it would be a mistake to overlook the fact that prices in the day-ahead market are highly vulnerable and, subsequently, tend to change quickly. For instance, a sudden drop of production, or an increase in demand, sends the price soaring because the stock of goods available for immediate delivery may be limited. On the opposite, a glut in production or a dip in demand will lower the price. Moreover, day-ahead market price (DAP) also reacts to news related to the future availability of other commodities such as oil and coal, or even to weather forecasts. All in all, variations in DAP are not only larger but also highly unpredictable and that, amongst all other questions, is what makes life harder for both consumers and producers of electricity.

Although being in business means taking some risks, an excessive amount of risk endangers the survival of a business. Most participants in the day-ahead market desire, therefore, to mitigate and reduce their exposure to risk. On one side, a consumer will typically try to establish a maximum price to pay for the commodity. On the opposite side, the producer of a commodity will try to avoid being forced to sell its output at a very low price. This will to avoid being vulnerable to the price fluctuations has led to the introduction of other types of transactions and markets (intraday, futures and forwards markets, for instance) [15].

2.3.3 MIBEL's intraday market

The purpose of the intraday market in the electricity wholesale market is to respond, through the presentation of electricity power sell and purchase orders by market agents, to adjustments made to the final viable daily schedule. Intraday (ID) markets cover energy negotiated in open markets after the day-ahead time, and prior to System Operator real-time security interventions. Consequently, ID markets represent the last opportunity for market agents to balance their schedules in a multilateral market environment, without the direct intervention of the system operator in their transactions [14].

In essence, the intraday market follows the same strategy that is used in the day-ahead market. On one side there are the energy sellers and on the other the energy purchasers. Both specify the amount and respective price of energy they want to sell/buy to the market operator. Then, the market operator matches the orders and the price of each intraday session corresponds to the last matched ask. The only dichotomy amongst the day-ahead and the intraday market relies on the number of sessions and respective deadlines. The day-ahead market has only one session, whereas, the intraday market is divided in six sessions, each one for the same day but with different deadlines, as one may witness in Figure 2.17.

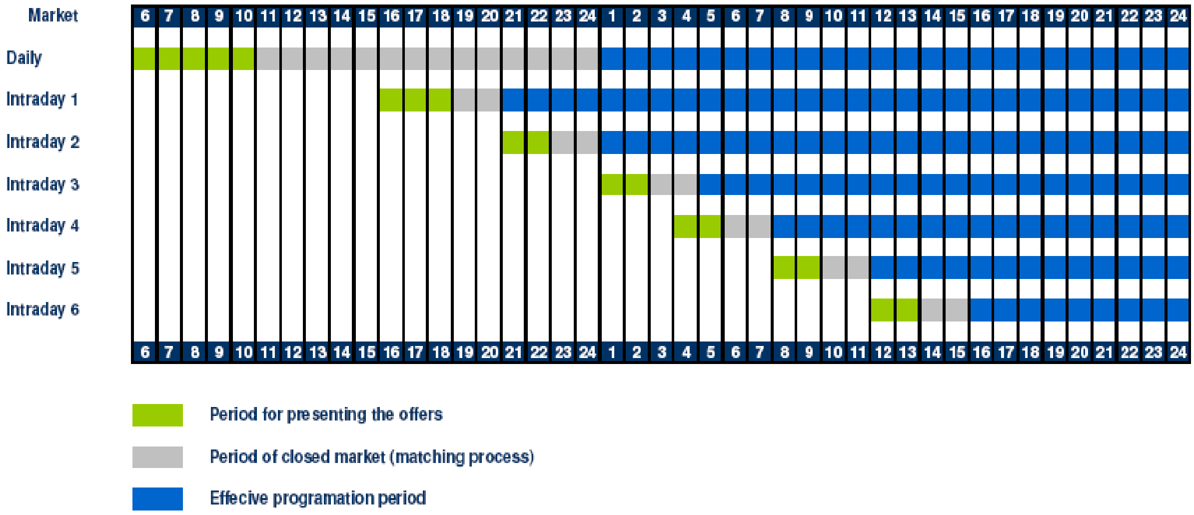

Figure 2.17 – Bidding periods for the day-ahead market and the ID market [16].

Figure 2.17 can be complemented with more accurate information related with the hourly distribution of each ID session. This information is presented in Figure 2.18.

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	16:00	21:00	01:00	04:00	08:00	12:00
Session Closing	17:45	21:45	01:45	04:45	08:45	12:45
Matching Results	18:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	18:45	22:45	02:45	05:45	09:45	13:45
Constraints Analysis	19:20	23:10	03:10	06:10	10:10	14:10
Adjustments for Constraints Publication PHF	19:35	23:20	03:20	06:20	10:20	14:20
Schedule Horizon (Hourly periods)	28 hours (21-24)	24 hours (1-24)	20 hours (5-24)	17 hours (8-24)	13 hours (12-24)	9 hours (16-24)

Figure 2.18 – Hourly distribution of each ID session (CET) [14].

Looking at Figure 2.18, we rapidly come to the conclusion that the last 4 hours are the ones which have more opportunities to be corrected in the ID market. On the opposite, there are very few chances to alter the first 4 hours. Indeed, only ID1 and ID2 offer the possibility to change the prediction for the first four hours. Hours 21, 22, 23 and 24 have all 6 intraday markets available to be corrected. The explication to this phenomenon relies on the fact that the first four hours are the closest ones, in terms of temporal horizon, to the deadline for presenting the orders on the daily market. Due to that proximity, previsions are less likely to fail. The last four hours, though, are less susceptible to be correct by that period. Subsequently, it is imperative to offer more ID sessions for the producers to revise their previsions.

All agents authorised to present electricity sale or purchase orders on the day-ahead market and who have participated in the corresponding day-ahead market session in which the intraday market session is opened, or who have executed a physical bilateral contract, may participate in the intraday market.

Intraday markets are a vital tool for market parties to keep positions balanced as circumstances taken into account in the planning of injections and/or off-take may change between the day-ahead stage and nearer to real time operations. Within this field, some intermittent renewable generation benefit from this real time corrections. Photovoltaic and wind energy, for instance, find it very difficult to have accurate predictions. This may not be a problem as long as they do not participate in the wholesale market. However, in countries like Spain, where wind energy is no longer managed out of the market, wind producers learned from themselves the importance of having a platform that enables them to change the first predictions for the production of wind power for a certain hour. This strategy is fundamental to avoid the generally high costs of the denominated "balancing mechanism" which is frequently perceived as a penalty imposed on the purchase price of balancing energy. This penalty may be explicit, such as a multiplicative factor applied to the supply cost of the balancing mechanism, or implicit, integrated into the method by which the balancing price is computed. Generally, balancing mechanisms provide for at least two different prices for imbalances. One price is applied to positive imbalances, in which energy supplied in excess of the schedule is remunerated at below the marginal cost of the systems balancing. Another price exists for negative imbalances, in which energy supplies below the schedule are priced higher than the marginal cost of systems balancing. This strategy is followed mainly in Europe. Experts defend that, in this procedure, participants in forward markets have an incentive to increase the risk exposure of the electricity system by raising the amount of balancing power transacted during real time. Practically, penalizing real-time imbalances also has the effect of transferring some of the risk and responsibility for balancing from the system operator to the market participants.

Portugal is reaching the time when the feed-in tariff of wind energy will end and wind producers will start to give preponderance to the intraday market. Yet these balances are only possible if the market is sufficiently liquid. Otherwise not all participants will be able to find counterparties to offer them additional contracts to modify their daily schedules.

3 Wind farm in a market environment – Practical implementation

This chapter aims at describing the algorithms used to implement the market simulator that will allow the forecasting of a particular wind farm's economical outcome in a market environment. Once the case study applies to a regional integrated market – MIBEL – in which cross-border trade is a key issue, the fundamentals of capacity allocation and congestion management methods will be addressed.

3.1 Congestion management – The market splitting mechanism

In this section it will be described the main congestion management methods, with particular emphasis to market splitting.

3.1.1 Examples and differences of congestion management methods

According to the Regulation (EC) N. 714/2009, congestion means a situation in which an interconnection linking national transmission networks, cannot accommodate all physical flows resulting from international trade requested by market participants, due to lack of capacity of the interconnectors and/or the national transmission systems concerned. At the present time, the European Commission supports every market mechanism which increases the level of integration of the existing electricity markets in Europe. Market integration is the prerequisite for the creation of a single European electricity market.

Transmission System Operators, TSOs, are major actors in the process of market integration, for improving the efficiency of the use of existing infrastructures as well as for developing new infrastructures. With regard to the use of existing cross-border infrastructures TSOs are in charge of calculating the maximum cross-border capacities, allocate them to the market and publish the data related to those capacities. Regarding the cross-border capacity maximization, TSOs are requested to build and guarantee the necessary capacity for market functioning without permanent or structural congestions. Furthermore, concerning the use of cross-border transmission capacity, TSOs are in duty of adopting congestion management methods which give efficient signals to them and to market participants. Within this context, they also need to optimise the degree to which capacity is firm. In Portugal this role is played by a sole entity, REN, whereas in Spain it is performed by Red Eléctrica de España − REE.

Congestion methods can have different objectives and meanings. Some of them are meant to allocate optimally the available capacity to the market participants while meeting the security constraints, others must deal with already existing congestion or predicted congestion on day minus one (D-1). The differences between these two issues are significant and accordingly they should be separately assessed as well. The first group is capacity allocation methods (pro-rata, priority based rules, explicit and implicit auction (market splitting or market coupling)), while the second group is congestion alleviation methods (redispatching and counter trading).

3.1.2 Capacity allocating methods

The capacity allocation methods can be subdivided in two categories: explicit and implicit, as it can be witnessed in Figure 3.1.

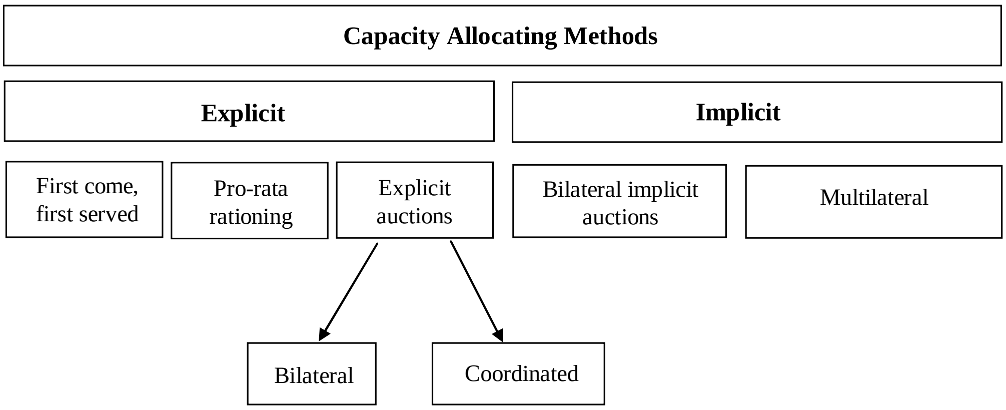

Figure 3.1 – Capacity allocating methods.

Explicit Auctions

In explicit auctions, each market participant offers a price for use of the Net Transfer Capacity (NTC[16]). The bids of the participants are stacked, highest bids first, until the NTC is completely used. Often, a "transmission market" clearing price is calculated and each participant pays this. Several methods to fix both the clearing price and the volume of capacity allocated exist. Once the NTC is completely used, either the process is stopped, or there is some re-dispatching, according to the level of the clearing price and the process may go on with extra trade possibilities. Figure 3.2 illustrates the explicit auctioning procedure [17].

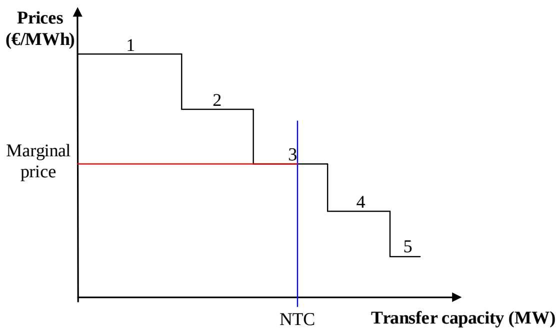

Figure 3.2 – Explicit capacity auction.

Revenues from this allocation method will arise only on interconnections that are expected to be congested[17]. To ensure that the explicit auction mechanism works properly, appropriate organisation of auctions in time horizons, secondary capacity markets, coordination in time and format in the different interconnections and open access to information are needed. Explicit auctions are divided in bilateral and coordinated. Bilateral explicit auctions occur when there are only two areas. In case there more than two areas it is denominated coordinated explicit auction. The first coordinated auctions have started among Poland, the Czech Republic, Slovakia and Germany.

[16] NTC = Total Transfer Capacity (TTC) – Transmission Reliability Margin (TRM).

[17] If the overall demand for transfer capacity is lower than the NTC, the auction clearing price must be zero, i.e. no congestion charges can be applied if there is capacity left that has not been requested by the market.

Explicit auctions are, indisputably, one of the main capacity allocation methods used in Europe. Indeed, for long and medium term, it is the recognised method by the European regulations and directives.

First Come, First Served

In the first come, first served method, the first reservation made for a given period of time has priority over the following reservations. Once the interconnection capacity is reached, the transactions are not accepted by the TSO anymore. Each reservation has to be confirmed at least on day D-1. Any change of schedule has to be notified to the TSO and penalties should be paid for last minute changes. This methodology encourages participants to make longer forecasts. Thus, it allows better and sooner security assessment for TSOs who know accurately the volume of exchanges in advance. However, in some cases, the method may not leave enough room for short term trading, which is a requirement to ensure the success of a market dynamics. Long term reservations may block transmission capacities for long periods, during which little short term market activity would take place.

Pro-Rata

Unlike the first come, first served method, in the pro rata mechanism no real priority is defined. All transactions are carried out but the TSO curtails them in case of congestion according to the ratio, existing capacity/requested capacity. This method is transparent to the users, but brings the participants to an economically inefficient use of the system: everyone being curtailed relatively to the amount submitted to the TSOs, no incentive is given to reduce congestion either to the participants, or to the TSOs. In the absence of regulatory mechanism, it may also lead to artificially over-evaluated amounts of transactions.

To clarify the differences between the pro-rata and the first come, first served methods, imagine a situation in which the cross-border capacity is 100 MW. If there are only two offers of 100 MW each for using the interconnection, in the pro rata method, the TSO will divide the cross border capacity according to the requested capacity in both offers. Consequently, in this situation, the TSO would allocate 50 MW of the interconnection capacity to each offer. If the methodology taken was the first come, first served, the first market participant to make the offer of 100 MW would be automatically allowed to use the entire capacity of the interconnection, independently of existing posterior offers. However, the first come, first served and the pro-rata are non-market based congestion methods that have almost run their course in Europe, as they are not recognised by the European directives and regulations.

Implicit Auctioning

Implicit auctioning is based on energy bids on each side of the interconnector. In a system of implicit auctioning, generators in area A that want to sell electricity in area B need to bid into an organised day-ahead market covering area B, directly (market splitting) or indirectly (market coupling). Contrary to explicit auctioning, implicit auctioning does not separate energy flows from transmission capacity, which makes the process simpler for market parties. They simply bid into a power exchange and the best bids are honoured, until the interconnector is used at full capacity.

There are, however, several practical barriers to applying implicit auctions across Europe. The main drawback of implicit auctioning is that it requires an organised electricity market, or at least a market place with a price index, at the downstream side of each congested interconnection. Between countries there is a wide diversity of physical arrangements (e.g. notification and balancing arrangements, transmission pricing, half hour or hourly metering) and exchange trading arrangements (block bids, intraday markets, matching rules) [17]. Portugal and Spain, though, operate their cross-border trade under an implicit auctioning method, market splitting, ran by OMEL that will be target of a detailed explanation in the subsequent sections. Alongside market splitting, market coupling is the other implicit allocation capacity method recognised by the European directives and regulations for the day-ahead market.

3.1.3 Congestion alleviation methods

Besides capacity allocation methods, there is another group within the congestion management methods, the alleviation methods. This group includes counter trade and redispatching. Actually, these are the "real" congestion management methods, as they operate when congestion occurs. Capacity allocation methods, as we saw, operate before the congestion, in a programming phase.

Counter Trade

In the counter trade methodology, the TSO requests the generators, in the bidding process, to regulate down a certain amount of generation on the surplus side of the bottleneck that is subsequently compensated. Similarly, generators on the shortfall side are paid to regulate generation up by the same amount. This amount of power will then flow in the opposite direction to the power flow that the market players want to transmit, and this synthetic extra transmission capacity can be made available to the players [17], as Figure 3.3 demonstrates.

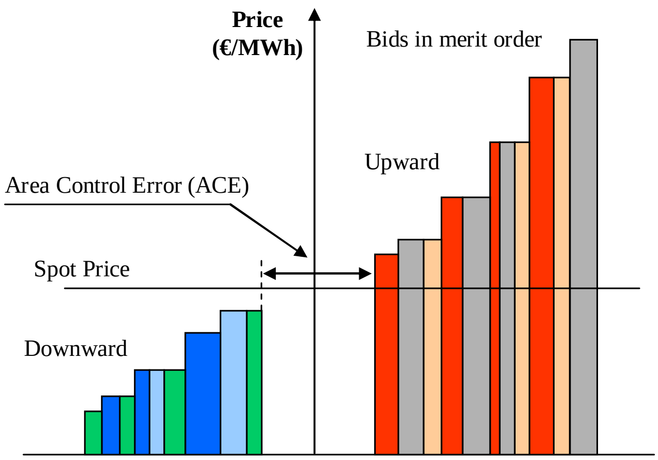

Figure 3.3 – Counter trading.

To clarify this methodology, let us give an elucidative example. Suppose the NTC between Spain and Portugal is, at a defined hour, 1000 MW. Imagine that, for some reason, in that hour, the NTC is reduced to 800 MW (due to a weather temperature increase, for example) when there was a flow of 1000 MW from Spain to Portugal. It is imperative to take some action; otherwise the transmission lines would not support such a power. An obvious solution would be building another line. However, if the system operator waited for that line to be built, by that time the system would have probably collapsed! The cross border flow, CBF, can be calculated, at any moment, as the difference between the consumption and production, in Portugal, (3.1).

$$CBF = \sum cons_{PT} - \sum prod_{PT} \tag{3.1}$$

In this case, if the CBF had to be reduced from 1000 MW to 800 MW, according to (3.1), two measures could be adopted: reduce consumption or increase supply. Generally, what happens is that the Portuguese TSO requests generators in Portugal to regulate generation up. In this particular situation, generators would have to increase their power up 200 MW, corresponding to the difference between the power currently in the interconnection and the new NTC in that hour. The TSO, in Portugal, would consequently buy this extra energy and resell it to the Spanish TSO (Red Eléctrica), as it does not correspond to an increase of demand in Portugal. On the opposite, generators in the Spanish side would be asked to regulate down the same 200 MW. The Spanish TSO would then sell the 200 MW that have previously bought from the homologous entity in Portugal to the Spanish generators that were ordered to regulate down. This is the commonly adopted solution in such situations. Yet, in an extreme situation, or in a favourable economic scenario, consumers in the Portuguese area could be involved in this process in order to reduce consumption. Typically, they are paid to be without supply of energy for a certain time.

Counter trade mechanism induces cost for the system operator since it must buy and resell energy according to the adjustment bids[18]. These costs are distributed among network users through the fixed charges of the network tariff.

Redispatching

Redispatching, conceptually, is similar to counter trading. It is used, though, in countries where a market for system services is not available. As a consequence the lowest-priced upward and downward regulation entities are chosen on the basis of the knowledge of marginal generation costs of all generators. Redispatching requires the existence of a central body to run a continuous overall load dispatch system.

3.1.4 Market splitting

Market splitting is today generally regarded as the most efficient and transparent congestion management method for day-ahead capacity allocation. Alongside market coupling, they both are the two implicit capacity allocating methods used in Europe. Indeed, the conception behind these two mechanisms is almost identical. The main difference is that market coupling is organised with two or more power exchanges. Market splitting is adopted when one power exchange is in charge of managing a day-ahead market for several bidding areas, reason why Portugal and Spain operate their cross-border capacity under this mechanism. The aim, though, is shared by both methods: improve the economic surplus as a result of a better use of the interconnections.

Market splitting is a system wide optimisation, in order to make a better use of the cross-border transmission lines. This method consists of splitting a power exchange market into geographical bidding areas with limited capacities of exchange. A clearing unconstrained price is set according to the amounts of demand and generation

[18] It is likely that the regulating up prices are higher than the regulating down ones.

offered in the whole market area. Then the TSO computes the relevant load flows and identifies constrained lines. Geographical areas composed of one or more biding areas are defined on either side of the bottlenecks. In each geographical area, a clearing price is defined, flows across areas being limited to the capacity of the interconnection lines. Then each area has its own clearing price: areas downstream of a congestion will have a higher pool price, areas upstream of a congestion will have a lower clearing price.

Assuming a system with two areas A and B, in a first step the power exchange computes the equilibrium price and the allocated quantities to market agents. From these results, two situations are possible:

1. The resulting cross-border flow is lower than or equal to the Net Transfer Capacity (NTC);
2. The resulting cross-border flow is higher than the NTC.

In the first case, the result is valid and final, i.e. both areas share the same equilibrium price.

In the second case, a second iteration is needed. The initial unique market with bids and asks from both areas is divided in two markets: one with the area A orders and other with the area B ones. These two markets have, though, an additional parameter, which refers to the interconnection capacity. Indeed, we know that whatever the final outcome is, there will be a power flow with a value equal to the NTC from the low price area to the high price area. To implement that restriction in the matching algorithm, in the exporting market it is introduced an instrumental bid at the highest price[19] with a volume equal to the value of the NTC. Identically, in the importing market there is an extra instrumental ask with a volume equal to the value of the NTC at zero price. These two instrumental orders represent the power that is exported from the area with lowest price to the one with the highest price. The bid price of that order is the highest possible to assure that it is matched. The same philosophy is applied to the ask price in the importing market. Figure 3.4 illustrates the general concept of market splitting.

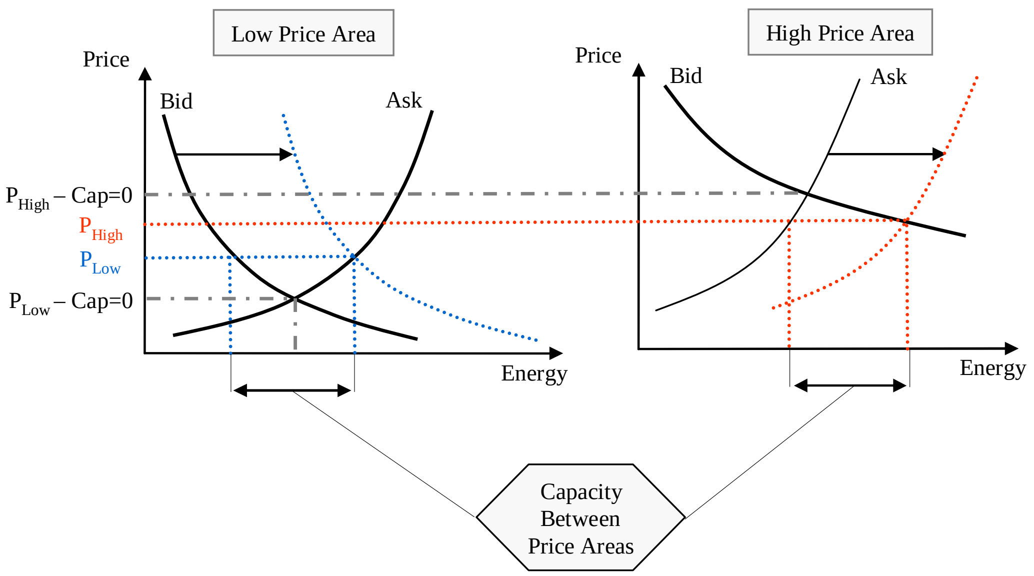

Figure 3.4 – Implicit capacity allocation – Market Splitting.

Moreover, in market splitting and in market coupling models a congestion rent – market operator revenue (*MOR*) – is generated and collected by the market operator(s) that arises from the price difference between the different

[19] In OMEL model, the maximum price available for orders is 18.03c€/kWh, or 180.3 €/MWh.

bidding areas and the cross-border flow. That congestion rent is proportional to difference of prices in the two areas, as it can be seen in (3.2)[20].

$$MOR = (P_B - P_A) \times NTC \qquad (3.2)$$

The origin of (3.2) is the following: the market operator overall settlement for a specific hourly period is[21]:

$$MOR = (QBuyers_B \times P_B + QBuyers_A \times P_A) - (QSellers_B \times P_B + QSellers_A \times P_A). \qquad (3.3)$$

Where:

$QBuyers_A$ and $QBuyers_B$ are the aggregated buyers quantity in area A and B, respectively;

$QSellers_A$ and $QSellers_B$ are the aggregated sellers quantity in area A and B, respectively;

P_A and P_B are the marginal price in area A and B, respectively.

Rearranging the terms, (3.3) can be written as (3.4):

$$MOR = P_B \times (QBuyers_B - QSellers_B) + P_A \times (QBuyers_A - QSellers_A). \qquad (3.4)$$

However, the market splitting mechanism imposes that the unbalance between aggregated buyers and sellers quantities, in each area, corresponds to the cross-border flow between areas, and its value is imposed by the available interconnection capacity for that flow, the NTC. Considering that NTC values assume positive and negative values according to the direction of the flows and that the flow from A to B is the positive direction:

If $P_B > P_A$, it means that there is a flow from A to B and then:

- $(QBuyers_B - QSellers_B)$ = NTC (>0);
- $(QBuyers_A - QSellers_A)$ = – NTC (<0).

If $P_A > P_B$, it means that there is a flow from B to A and then:

- $(QBuyers_B - QSellers_B)$ = NTC (<0);
- $(QBuyers_A - QSellers_A)$ = NTC (>0).

Therefore, we reach equation (3.2).

Using the same hypothesis, market coupling and market splitting should lead to the same results. Market coupling consists of coupling N markets, which results in a unique virtual market in case of no congestions, while market splitting starts with one single market which is split in several different markets in case of congestions. Market coupling allows an integration of several markets, even if they have different designs. That is why in central Europe market coupling is more suitable.

3.2 Case study – MIBEL implicit auctions algorithm

Market splitting is the implicit capacity allocating method used between Portugal and Spain. In the following sections it will be presented the algorithm used in MIBEL, and consequently in this thesis which does not differ largely from the one overall algorithm explained in section 3.1.4. As a first step of the algorithm, market participants of both countries notify their bids and asks in the same market place (OMEL), specifying the

[20] In the case of MIBEL, the total congestion revenues between market splitting start (July 1, 2007) and September 30, 2009 is 120 M€.

[21] Considering revenues collected from buyers as positive values and the reverse for payments to sellers.

concerned area. OMEL, subsequently, integrates those bids and asks as part of the equilibrium price, EP, calculation. That calculation is explained in section 3.2.1.

3.2.1 Equilibrium price calculation

The algorithm applied by OMEL to compute the equilibrium price follows a marginal price, sealed bid auction model, which assumes a merit order that considers that higher bid prices and lower ask prices are more favourable prices, like in any market. The EP is determined according to the following criteria:

1. Maximum tradable volume (MTV);
2. Minimum price (mP) – if there is more than one price with equal value for the MTV, the minimum price is chosen[22].

Thus, the equilibrium price (or clearing price) is the minimum price at which the biggest possible volume can be executed.

The execution of the algorithm that computes the EP starts by defining the Tradable Volume (TV) for each order price limit present in the order book. The tradable volume is determined according to (3.5),

$$TV(P_i) = \min[BidVolume(P_i); AskVolume(P_i)] \tag{3.5}$$

where:

Bid Volume (Pi) = Aggregated volume of bids orders with prices ≥ Pi;

Ask Volume (Pi) = Aggregated volume of ask orders with prices ≤ Pi;

(Pi) = Different order prices limits (1 to i).

Once the series of TV values has been computed, one for each individual order price limit, the maximum value is selected as the MTV, and the corresponding price limit defined as the EP. If more than one price limit originates the MTV, the lowest of those prices is chosen as the equilibrium price. Figure 3.5 presents a simplified illustration of the equilibrium price (EP) determination, where three different prices are selected, with the corresponding TV [11].

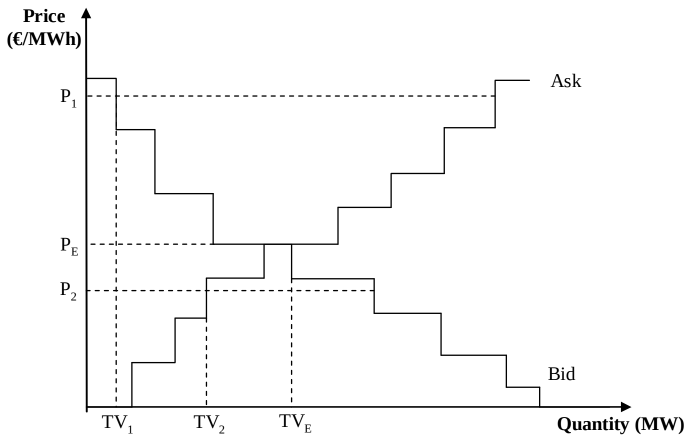

Figure 3.5 – Equilibrium price algorithm exemplification.

[22] This is obviously a result of OMEL day-ahead market design, in which orders are linked to physical delivery or consumption. Accordingly, bids for consumption are instrumental orders at maximum price and therefore the minimum price criterion has to be used.

The bid and ask curve (or buy and sell curve, respectively) of Figure 3.5 would produce the following result: EP = P_E and MTV = TV_E.

To illustrate the main features of the algorithm, some examples are presented which cover the more straightforward cases, with one single price for the MTV. Some other scenarios, where there is more than one price for the MTV, are also considered. The examples consist of the order book status before the equilibrium price is established, and the resulting series (price limit; bid volume; ask volume; TV), in order to show the main characteristics of the referred algorithm. The chosen equilibrium price in the examples below is shown in bold.

Example 1

In this first example, a simple scenario with one single pair, price limit; MTV, is presented.

Table 3.1 – Example 1 – Call Auction: Bid, Ask and Tradable Volumes [11].

Bid		Ask	
Volume	Price	Price	Volume
20	49.00	47.00	20
30	48.50	48.50	50
40	48.00	49.00	30
30	47.00		

Price	Bid Volume	Ask Volume	Tradable Volume
49.00	20	100	20
48.50	**50**	**70**	**50**
48.00	90	20	20
47.00	120	20	20

The equilibrium price is given by the price limit which produces the MTV: 48.50 €/MWh.

Example 2

In this example, all price limits present in the order book produce the same MTV, 50 MWh.

Table 3.2 – Example 2 – Call Auction: Bid, Ask and Tradable Volumes [11].

Bid		Ask	
Volume	Price	Price	Volume
50	61.00	58.00	50
30	60.00	61.00	50
20	59.00		
50	58.00		

Price	Bid Volume	Ask Volume	Tradable Volume
61.00	50	100	50
60.00	80	50	50
59.00	100	50	50
58.00	**150**	**50**	**50**

The EP is determined by the application of the second criterion: if there is more than one price with equal value for the MTV, the minimum price is chosen. Consequently, the solution is 58.00 €/MWh.

Example 3

This scenario is characterized by having two price limits producing the same MTV, 35 MWh.

Table 3.3 – Example 3 – Call Auction: Bid, Ask and Tradable Volumes [11].

Bid		Ask	
Volume	Price	Price	Volume
10	49.00	47.00	10
70	48.50	47.50	10
40	47.50	48.00	15
20	47.00		

Price	Bid Volume	Ask Volume	Tradable Volume
49.00	10	35	10
48.50	80	35	35
48.00	**80**	**35**	**35**
47.50	120	20	20
47.00	140	10	10

Again, by the application of the second criterion, the EP is chosen from the pair (price limit; MTV) with minimum price, 48.00 €/MWh.

Example 4

This situation results in two price limits producing the same MTV, 40 MWh.

Table 3.4 – Example 4 – Call Auction: Bid, Ask and Tradable Volumes [11].

Bid		Ask	
Volume	Price	Price	Volume
40	49.00	46.50	10
30	47.50	47.50	10
40	47.00	48.50	20
50	46.50		

Price	Bid Volume	Ask Volume	Tradable Volume
49.00	40	40	40
48.50	**40**	**40**	**40**
47.50	70	20	20
47.00	110	10	10
46.50	160	10	10

Once more, by the application of criterion 2, the EP is chosen from the pair (price limit; MTV) with minimum price, 48.50 €/MWh.

3.2.2 Trade allocation

Trade allocation is what follows the determination of the equilibrium price. It is processed according to the following criteria:

1. All orders that are better (higher bids and lower asks) than or equal to the equilibrium price are filled, according to price priority, until the MTV is reached;
2. If two or more orders have prices better than or equal to the EP and cannot be totally filled, because the order volume of that side of the order book is greater than the MTV, a pro-rata methodology is applied. Instead of this pro-rata mechanism, a First In First Out priority criterion could be used, meaning that orders with higher time priority (stored earlier in the order book) are filled. However, OMEL opts for the pro-rata [11].

The pro-rata methodology has three main steps:

1. Assess which volume, bid or ask, is subject to the pro-rata. This is achieved by comparing both ask volume (AV) and bid volume (BV) with the maximum tradable volume (MTV). The one that exceeds the MTV is subject to pro-rata;
2. Calculate the exact volume subject to pro-rata. That volume is denominated the volume to assign (VA) and represents the volume available to divide by each order subjected to the pro-rata process, i.e. the volume matched at EP that has not yet been assigned to higher priority orders;
3. Determine the volume to assign to each individual order subjected to the pro-rata process. In other words, how the VA will be divided by the involved orders.

Appendix B clarifies the application of the pro-rata methodology and the application of these 3 steps, offering 3 situations of possible bid-ask curves.

3.2.3 Assessing market splitting conditions

After running the equilibrium price algorithm with orders from both countries in one common market and applying the pro-rata method (if required), it is necessary to calculate the power that is exported by one area and imported by the other, i.e. the cross border scheduled flow (IF). This step is vital because without knowing the IF, it is impossible to know if the cross border scheduled flow exceeds the net transfer capacity (NTC) and, subsequently, if the corresponding generation and demand schedule would lead to a congestion.

The IF in this algorithm is determined by (3.6):

$$IF = AskVol_{PT} - BidVol_{PT} . \tag{3.6}$$

The $AskVol_{PT}$ corresponds to the aggregated volume of Portuguese ask orders with prices smaller or equal to the EP, after the pro-rata process was executed (AiPT is a Portuguese selling order) (3.7).

$$AskVol_{PT} = \sum_{i=1}^{n} AiPT, while[price(AiPT \leq EP)] \tag{3.7}$$

On the other hand, the $BidVol_{PT}$ corresponds to the aggregated volume of Portuguese bid orders with prices higher or equal to the EP after the pro-rata process was executed. Equation (3.8) shows that correspondence (BiPT is a Portuguese purchasing order).

$$BidVol_{PT} = \sum_{i=1}^{n} BiPT, while[price(BiPT \geq EP)] \tag{3.8}$$

Note that the pro-rata method is crucial for the determination of both $AskVol_{PT}$ and the $BidVol_{PT}$, as it gives the possibility to know the exact volume assigned to each purchase and selling order.

Furthermore, it is also imperative to know the direction of the flow in the interconnection. With the definition in (3.6), if the value of the interconnection flow is positive, it means that the Portuguese area has an excess in generation (the supply orders exceed the purchase ones). Consequently, the flux of power will be from Portugal to Spain in these situations. On the other hand, in case the interconnection flow assumes a negative value, it means that the purchase orders exceed the selling ones in Portugal. So, in those situations Portugal plays the role of the importing area, due to a deficit in generation. Note that the IF could also be determined in relation to Spain. Obviously, the same conclusions would be reached.

Once the interconnection flow resulting from the first equilibrium price calculation has been computed, the next step of the algorithm is comparing the IF with the net transfer capacity (NTC). If it does not exceed the NTC, the price in both countries, Portugal and Spain, is identical, because there is no congestion and calculation process reaches its end for the considered hourly period. However, if the IF exceeds the NTC, i.e. the interconnection capacity available for commercial transactions is exceeded, the initial single market with asks and bids from both countries is split in two separated markets, with the interconnection capacity being set at its limit. Note that the sign of IF determines the NTC value to be compared with: if positive it has to be compared with the Portugal-Spain NTC value, whereas if negative it is the opposite comparison that is carried out to assure that both situations of importation and exportation are covered[23].As it was highlighted in section 3.1.4, each one of the two markets have now one additional instrumental order corresponding to the NTC value (bid @ 183.3 €/MWh in the exporting area and ask @ unconstrained (pre-splitting) equilibrium price), which is generated by the algorithm. The only difference in relation to the algorithm explained in that section is that the instrumental selling order, which was considered at 0 €/MWh, is set by OMEL at the price of the first EP calculation, due to the stepwise characteristic of the bid and ask curves.

3.3 Algorithm for wind producers attending the power market

This section will address the algorithm applied in this thesis to study the incorporation of wind energy in the electricity wholesale market. This explanation will be supported by four major topics: strategy, which scrutinizes the overall relation of wind farms with the different markets of MIBEL, generation forecasts, which brings forward the two wind prediction methods used in the work, implementation, where the main features of the adopted algorithm are described, and assumptions, reporting the hypothesis taken.

3.3.1 Strategy

As one may perceptibly agree, the foremost aim of wind farms while attending the power market is the maximization of global economical results taking into account the overall operating cycle: day-ahead, intraday and system operation balancing.

To start with, participation in the day-ahead market is mandatory, under the penalty of not being allowed to take part in the several sessions of the intraday market. In this involvement in the daily market, the wind producer transmits to the market operator the generation forecast for the 24 hours of day D. This forecast must be communicated until 10:00 (CET) of day D-1. Subsequently, in order to adjust the generation schedule, the wind unit ought to take part in the intraday market. Figure 3.6 illustrates the number of programming times, i.e. the number of times that the generation can be corrected in each hour, in the day-ahead and intraday markets.

[23] The NTC value may be different for the flow Portugal-Spain and Spain-Portugal, in the same hour.

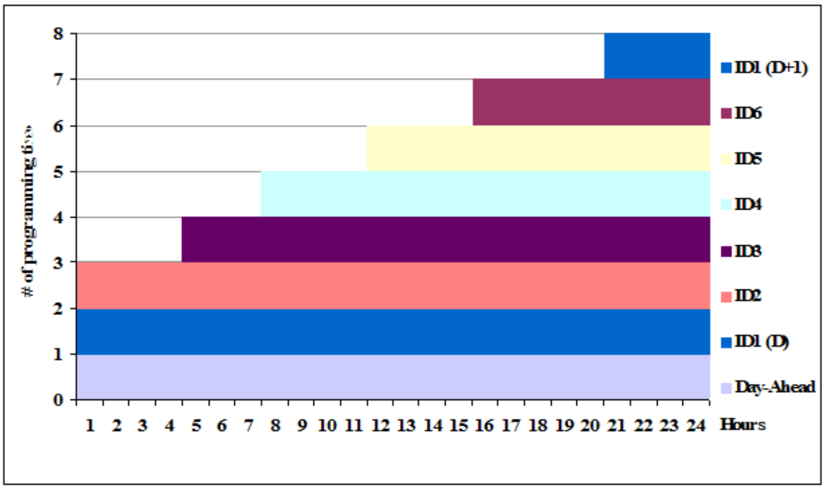

Figure 3.6 – Number of programming times for each hour in the day-ahead and ID markets.

As it was mentioned in chapter 2, the first four hours are the ones which have less possibilities of being corrected. This occurs because they are the closest, in terms of temporal horizon, to gate closure time (GCT) of the day-ahead market and therefore, less likely to be highly inaccurate. On the opposite, the last four hours stand as the ones that can be more times adjusted, following their temporal delay in comparison to the closing of the daily market. In Figure 3.7, it is exemplified this adjustment scheme in the different ID sessions for one of the last four programming hours.

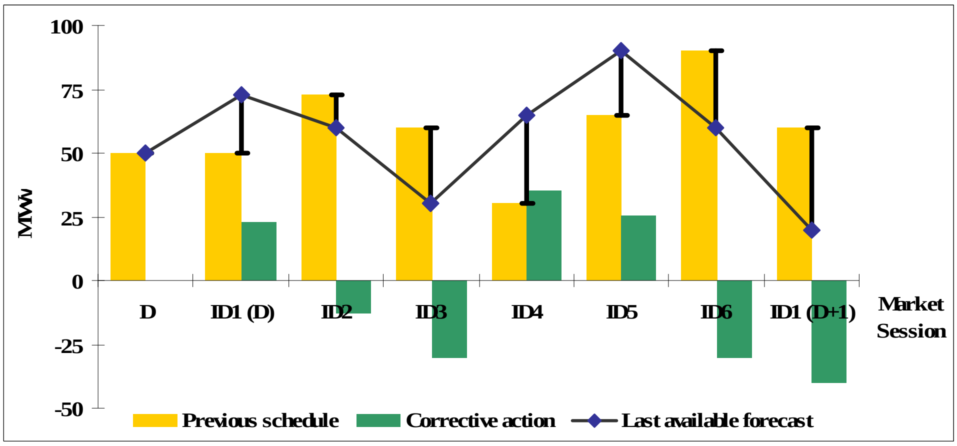

Figure 3.7 – Example of successive corrections in the ID sessions of one of the last four programming hours.

Figure 3.7 highlights that the corrective action, CA, can be determined as:

$$CA = LAF - PS \tag{3.9}$$

where:

LAF is the last available forecast;

PS is the previous schedule.

Taking into consideration the situation in Figure 3.7, in the day-ahead market, the wind producer transmits to the MO that he forecasts a generation of 50 MW during one of the last four programming hours, let us say hour 24, for instance. However, in the first session of the intraday market, ID1 (D), he alters that prediction to 73 MW. Therefore, the CA is 23 MW. In the second session of the intraday market, ID2, the wind producer has a new prediction of 60 MW during the same hour 24, which results in a CA of -13 MW. This procedure continues until the last intraday session is reached.

Indeed, these corrective actions are buying and selling orders performed by the wind producer in the different ID sessions. The price at which these orders are traded is the price of the different ID sessions. Figure 3.8 alludes for this fact.

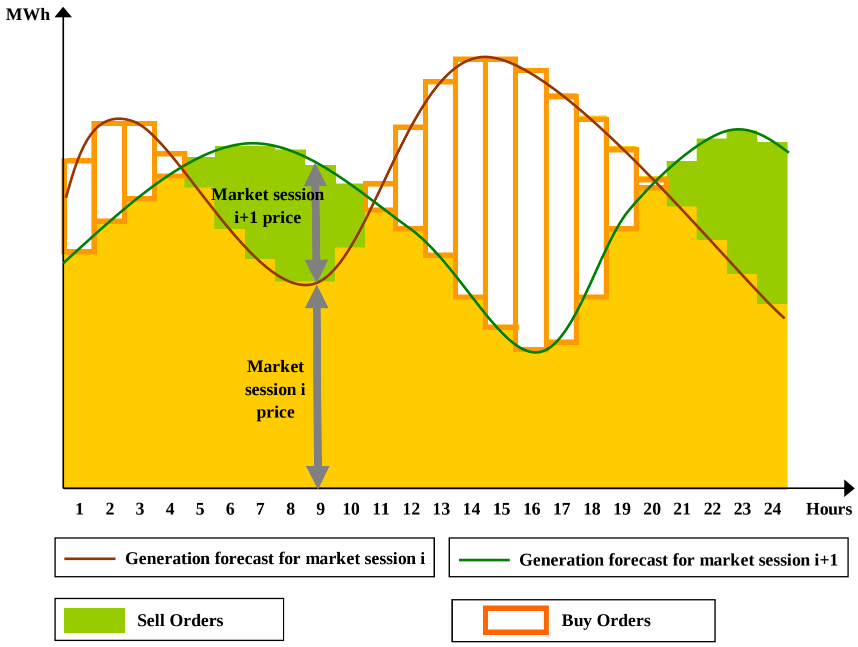

Figure 3.8 – Buy and sell orders performed by wind producers in the ID market sessions.

The representation in Figure 3.8 is general for two consecutive market sessions. In the first four hours of the illustration, the forecast in market session i was overestimated, according to the correction made in market session i+1. Consequently, the wind producer will have to buy the CA for each of the four hours in market session i+1. On the contrary, for hour 5 to hour 10, inclusively, the wind producer predicts he would be able to generate more power than he has previously forecasted. Hence, he will sell the quantity that corresponds to the corrective action in the market session i+1. This mechanism is applied to all 24 hours.

The participation in the ID sessions has one utmost purpose: the minimization of unbalance between last schedule and actual generation in order to avoid being penalised by the application of system operator unbalance costs. Figure 3.9 illustrates the application of these unbalance costs.

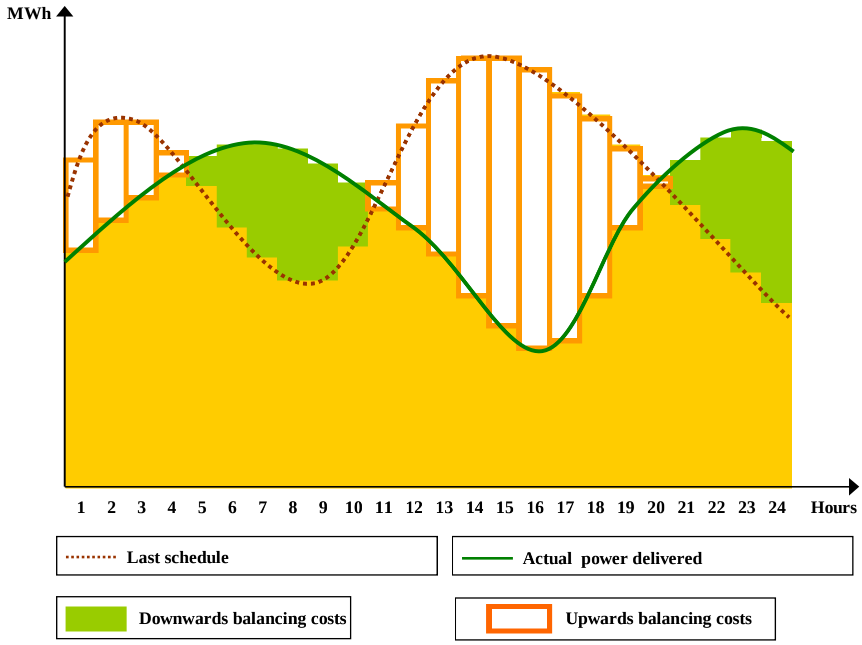

Figure 3.9 – Application of unbalance costs.

An upward balancing cost occurs, as it is demonstrated in Figure 3.9, when the actual power delivered by the wind unit is less than the one that was forecasted in the last schedule. The denomination, upward balancing costs, arises from the fact that the SO has to compensate the power that is not generated by the wind farm. Typically, the SO accomplishes this task by buying the deficit of energy to a conventional power plant. However, the wind unit is not immune to these costs. It will have to pay the SO for the amount of energy it was not able to produce at a price that is, on average, higher than the price of the different market sessions.

On the other hand, a downward balancing cost takes place when the wind unit generates more power than it has predicted in the last schedule. In these situations, the SO pays the wind producer for the extra amount of energy produced, at a price that is, generally, lower than the price of the different market sessions.

All in all, there is a very high probability of incurring in losses if the wind producer exposes himself to the SO balancing costs. In order to reduce that exposure, wind forecasts should be available as close to the deadline for orders submission[24] as possible.

3.3.2 Generation forecasts models

With the purpose of testing the strategy delineated in the previous section, two forecasting methodologies were used: NWP, numeric weather prediction, and ARMA, autoregressive moving average.

3.3.2.1 Numeric Weather Prediction, NWP, methods

Several physical models have been developed based on using weather data with sophisticated meteorological models for wind speed forecasting and wind power predictions. NWP models employ equations governing the

[24] Gate Closure Time (GCT).

motions and forces affecting motion of fluids. From the knowledge of the atmosphere's present state, the system of equations allows to estimate what the evolution of state variables, e.g. temperature, velocity, humidity and pressure, will be for a grid of surrounding points around the wind generators.

These models calculate how the atmosphere will change in each time and how each grid point will affect its neighbours, thus building a forecast of incoming events. According to the type of NWP system, these forecasts are given with a spatial resolution. Moreover, information related with the terrain effect, for instance, the terrain features, height, local surface roughness and shelter from obstacles, can be included in the physical equations. Nevertheless, collecting the information of terrain conditions is one of the mains difficulties in the implementation of physical models.

Since NWP models are complex mathematical models, they are usually run on super computers, which limits the usefulness of NWP methods for on-line or very-short-term operation of power system. In other words, meteorological models with high resolution are often more accurate but require high computation time to produce forecasts, and as a consequence, they do not update frequently their outputs. Therefore, the performance of physical models is often satisfactory for long[25] time horizons and they are on the other hand inappropriate for short-term prediction[26] alone due to difficulty on information acquisition and complicated computation.

An unstable atmospheric situation can lead to very poor numerical weather predictions and thus to inaccurate wind power ones. In contrast, as the atmospheric situation is stable, one can expect more accurate predictions for power because wind speed is the most sensible input to wind power prediction models. In general, a common approach to short-term wind power prediction is refining the output of numerical weather prediction models operated by weather services to obtain local wind conditions.

3.3.2.2 ARMA models

Autoregressive Moving Average (ARMA) models are relatively simple and inexpensive forecasting tools. They do not require a huge amount of historical data and, most significantly, they much improve the performance of the simplistic persistence model, which is normally taken as the reference model. The ARMA models can be characterized by (3.10) [18]:

$$X_t = \sum_{j=1}^{p} \phi_j X_{t-j} + \sum_{k=1}^{q} \theta_k e_{t-k} + C + \varepsilon_t \ . \tag{3.10}$$

Where:

X_t is the value of the time series for the instant t;

ϕ_j is the AR parameter for the lag j;

θ_k is the MA parameter for the lag j;

e_t is the value of the error for the instant t;

C is a constant;

[25] Larger than 6 hours ahead.

[26] Several minutes to one hour.

p is the Autoregressive order (number of the AR parameters);

q is the Moving Average order (number of the MA parameters);

ε_t is the white noise in ideal conditions.

Expression (3.10) states that a realization of the time series X at the time t depends on a linear combination of the past observations of X plus a moving average of series e_t. The time series X is known as an ARMA (p,q) process, where p is the order of the autoregressive process of X and q is the order of the moving-average error term. It is possible to imagine the ARMA model as a successive filtering operation which extracts the information present in the time series values in order to better represent it. These filtering operations are described in Figure 3.10.

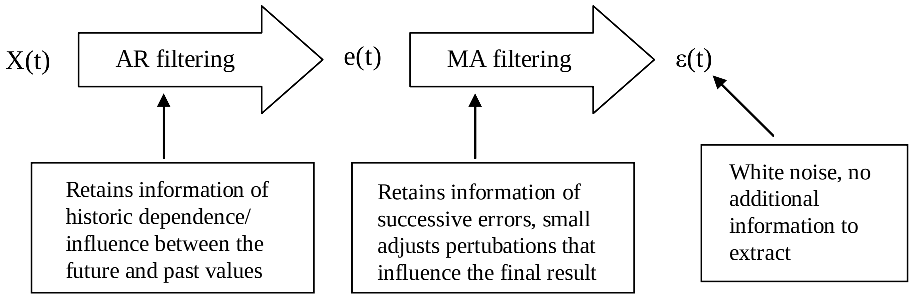

Figure 3.10 – ARMA filtering operations.

Firstly, the AR filtering extracts the information related with the historic dependences. It tries to recognise how the future values are influenced by the present and past values. Secondly, the MA filtering extracts the information related with the successive errors, which still affect the predictions after the AR filtering. Finally, the result of those two filtering operations will be the white noise, in ideal conditions. This means that, in ideal conditions, all information is extracted, and the past and present values do not have more additional information necessary to predict the future values.

In order to identify which time series model should be used for a certain time series it is followed the Box-Jenkins three stage methodology which includes: model identification, estimation and validation. The first stage is to determine the order of the AR and MA process, p and q, respectively. It involves the examination of the series autocorrelation and partial correlation functions. In the estimation phase, the model parameters are calculated using non-linear or maximum likelihood estimation procedures. Ultimately, the validation involves diagnostic checking of the model residuals to detect evidence of model fit [18]. The three stage methodology is represented in Figure 3.11.

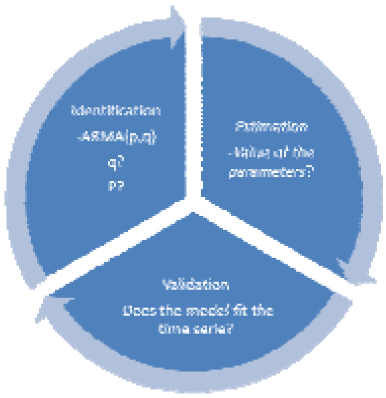

Figure 3.11 – Three stage methodology for identifying the ARMA structure [18].

If at the end of the procedure more than one model fits the data, a set of criteria are used in order to choose the best one. It is generally considered good practice to find the smallest values of p and q that provide an acceptable fit to the data. In more formal way, the accuracy ranking of the top performing ARMA structures is obtained after the application of *Akaike Information Criterion* (AIC) and the *Bayesian Information Criterion* (BIC) to the selected models. The one which presents the smallest value of the AIC and BIC is the ARMA model that better represents the original time series [18].

3.3.3 Implementation

The first step of the developed algorithm is obtaining wind – and generation – forecast for next day day-ahead market session. Once that prediction is completed, the wind producer sends the ask orders to next day day-ahead market at an instrumental price, 0 €/MWh, what makes him price acceptant orders (market orders), as the producer takes the price defined by the market. This happens because the day-ahead market is based on a marginal price auction, i.e. all buyers pay and all sellers receive the clearing price. The rationale for this strategy is that any market price higher than 0 €/MWh is a good price for wind farms in general, because their variable generation cost is very low.

Secondly in the algorithm comes the adjustment of the generation schedule in the intraday markets, in order to minimize the final unbalance with system operator. The orders performed by the wind producer in the different intraday sessions correspond to the difference between the last available forecast and the previous schedule[27]. The price of these orders should not be instrumental because, unlike the day-ahead market, intraday markets are less liquid and there is the risk of the price to reach limit values, high or low, depending on the adjustment signal.

The last main feature of the algorithm is the power adjustment made by the SO. Table 3.5 shows the relation of the balancing made by the SO with the adjustment of the wind farm.

[27] Net power of all transactions executed.

Table 3.5 – Comparison between the adjustments made by the wind farm and the SO.

	Wind Farm	SO
Actual Generation in comparison with LAF	↑	↓
	↓	↑

The interpretation of Table 3.5 is the following: when there is an adjustment up made by the wind farm, i.e. it produces more than it has forecasted in the last available schedule, the SO orders some conventional power plants to regulate down that extra power produced by the wind farm and remunerates the wind producer for that surplus at a downwards balancing price. On the contrary, in case there is an adjustment down of the wind power plant, meaning it was unable to generate the amount of power it forecasted, the SO will have to compensate that deficit of energy. The wind unit pays for that energy at an upwards balancing price[28].

According to the strategy explained in section 3.3.1, the wind producer should use all intraday opportunities to re-schedule. This would mean that each hour would be re-scheduled as many times as there were new forecasts for it. However, this solution is not optimum from the wind producer's economical perspective. If not note the following: why would the wind producer correct the last hours in the first ID sessions, if he is likely to have a more accurate forecast closer to that hours? Subsequently, the strategy adopted in this work is to adjust each hour only once, at the latest opportunity to do so. It means that only the latest intraday session that covers that hour is used to adjust the schedule that comes from the day-ahead market. In other words, in each intraday session, only the hours that are not covered by subsequent intraday sessions are corrected. The rationale to adopt this methodology is to minimize the economical losses that would arise from adjusting one hour several times with poor prices. Of course, other considerations, like sessions' liquidity and counterparties' availability are of outmost importance, but they are not explicitly considered in this modelling.

3.3.4 Assumptions

The algorithm carried out in this thesis is applied to a particular wind unit in the year of 2008. It was assumed that the introduction of this generation plant would not affect the market prices (day-ahead, intraday and deviation prices).

For the day-ahead market this assumption is acceptable, because if wind generation leaves feed-in tariff it means that the corresponding demand must also go to market (the last resort supplier only buys the net difference between the demand to supply and the generation with feed-in tariffs). In other words, this inclusion of the wind unit can be interpreted as a shift to the right of the bid-ask curve, Figure 3.12. Moreover, the relative weight in the day-ahead market would be very low.

[28] In the simple example it is considered that all deviations caused by the wind farm have to be directly managed by the SO. That is not generally the case in a complex system, as it is likely that deviations in opposite directions occur and the SO only sees the net effect of all them.

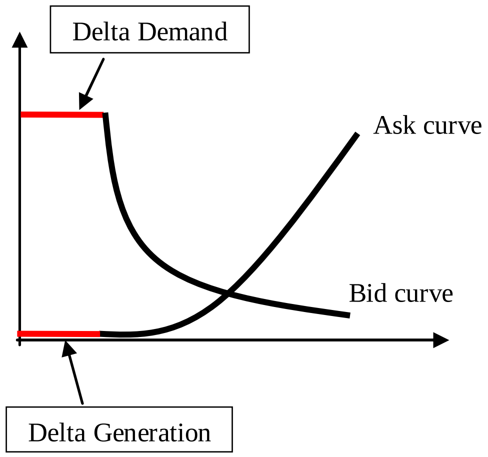

Figure 3.12 – Impact in the bid-ask curve made by the introduction of a wind unit in the power market.

Regarding the intraday market, the previous assumption is not applicable so straightforward. To start with, the netting effect is not valid, because wind generation adjustment ID orders are totally independent of demand adjustment ID orders. Moreover, ID markets are much less liquid and therefore the impact of additional orders on prices is more relevant. However, we opted to keep the prices of the different ID sessions unchanged, as the relative size of one wind farm is small and information on the resilience of the Portuguese intraday market is not available. This analysis is also suitable for the deviations prices.

Nevertheless, these hypotheses do not impact on the conclusions of this study.

The general expression used to calculate the revenue of the wind producer, R_{WP}, is (3.11).

$$R_{WP} = (DAS \times DAP) + \{(IDS - DAS) \times IDP\} + \{(AG - IDS) \times BP\} \tag{3.11}$$

Where:

DAS is the Day-Ahead Schedule;

DAP is the Day-Ahead market Price;

IDS is the Intraday Schedule;

IDP is the Intraday Price;

AG is the Actual Generation;

BP is the Balancing Price. The balancing price can be upwards, BPU, if the IDS exceeds the AG, or downwards, BPD, if the AG exceeds the IDS.

4 Results

In this chapter the results of the computation of the algorithms described in chapter 3 will be presented. Two main sets of results are considered: the first one, whose scope is the implementation of the market simulator algorithm, and a second group dedicated to the analysis of a wind farm's operation in a market environment.

4.1 Market simulator

The results of the market simulator consist of the relevant output for a market operator (clearing price and matched volume for the defined hourly period) as well as the aggregated supply and demand (bid-ask) curves for a particular hour. Two situations will be addressed.

In the first section (market simulator results), prices will be displayed in c€/kWh in order to allow a direct comparison with OMEL data published on its website [14]. In the second section (wind farm's operation in a market environment), standard pricing convention in power markets (€/MWh) will be used.

Situation 1

To start with, Figure 4.1 illustrates the bid-ask curve of 24/03/2009, 21st hourly period.

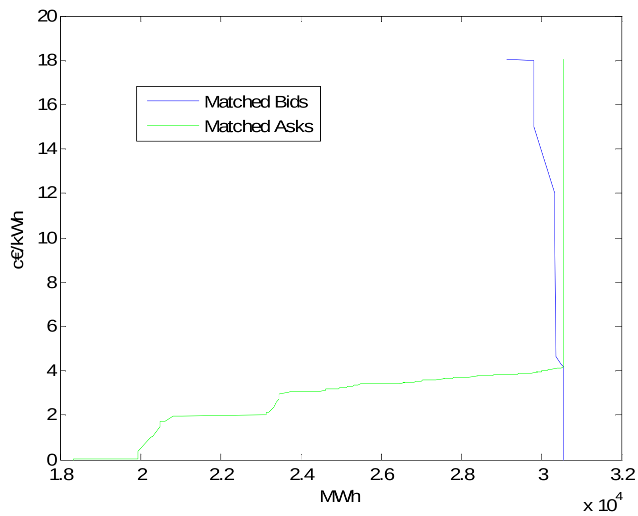

Figure 4.1 – Bid-ask curve of the 24th of March 2009, 21st hour.

The intersection of the bid and ask curves corresponds to the market clearing price. As it was mentioned in the second chapter, the market clearing price, MP, in each hour is equal to the price of the last block of the selling order of the last production unit whose acceptance has been required in order to meet the demand that has been matched. In this particular hour, the computation of the algorithm results in a MP of 4.175 c€/kWh. The total volume traded at MP, which is defined in chapter three as the maximum tradable volume, MTV, is, for this hour, 30578 MWh.

Figure 4.2 shows the OMEL's aggregate supply and demand curve for the same hourly period, 21st of 24/03/2009. This data is available in OMEL's public site [14] in the section market results → daily market → Aggregate supply and demand curves MIBEL.

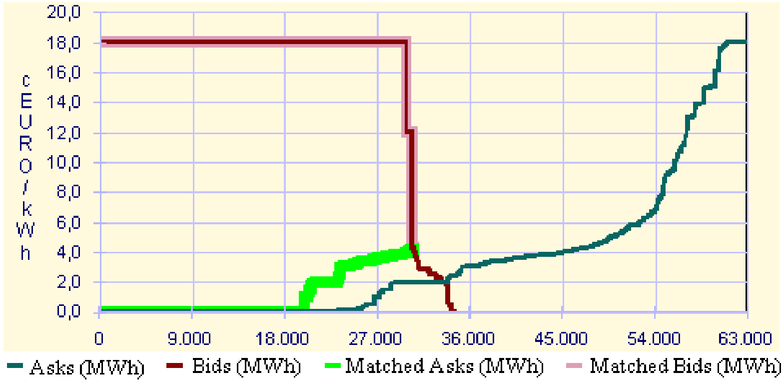

Figure 4.2 – OMEL's aggregate demand and supply curve (24/03/2009, 21st hour).

In Figure 4.2 two aggregate sell orders curves are visible, and it is clear that the light green curve results from the dark one by removing some orders (consequently there is a horizontal shift to the left of the remaining orders). This occurs because the light green curve does not incorporate the selling orders that were not matched due to complex conditions.

Complex asks are those that incorporate complex sale terms and conditions and those which, in compliance with the simple ask requirements, also include one or some of the following technical or economic conditions:

- Indivisibility;
- Load gradients;
- Minimum income;
- Schedule stop.

The indivisibility condition enables a minimum operating value to be fixed in the first block of each hour. This value may only be divided by the application of the load gradients declared by the same agent, or by applying distribution rules if the price is other than zero.

The load gradient enables to establish the maximum difference between the starting hourly power and final hourly power of the production unit, limiting maximum matchable power by limiting the variations between two consecutive hours, in order to avoid fast changes in output that the generation units would be unable to follow from a technical standpoint.

The minimum income condition enables the presentation of selling orders in all hours, and its consequence is that the generation unit does not participate in the daily matching result, if the total production obtained by it in the day does not exceed an income level above an established amount, expressed in euros, plus a variable remuneration established in euro cents for every matched kWh.

The condition of scheduled stop allows production units that have been withdrawn from the matching process, due to failure in comply with the stipulated minimum income condition, to carry out a scheduled stop for a maximum period of three hours [14].

It is possible to conclude that the matched bid-ask curves in both Figures, 4.1 and 4.2, lead to the same market price, 4.175 c€/kWh, as they have a similar shape. This value can be confirmed in OMEL's site, in the section market results → daily market → daily market hourly price. It is relevant to mention that, in this situation, the NTC was not exceeded. Therefore, the market price is equal in both areas, Portuguese and Spanish.

Furthermore, there is also a match in both Figures regarding the amount of energy traded in this particular hour, 30578 MWh, which can also be verified in OMEL's site.

Situation 2

This second situation is referred to the 17th hourly period of 24/03/2009, the same day of situation 1. The aggregated demand and supply curve that resulted from the first equilibrium price (EP) calculation, i.e. with bids and asks from both countries, Portugal and Spain, is represented in Figure 4.3.

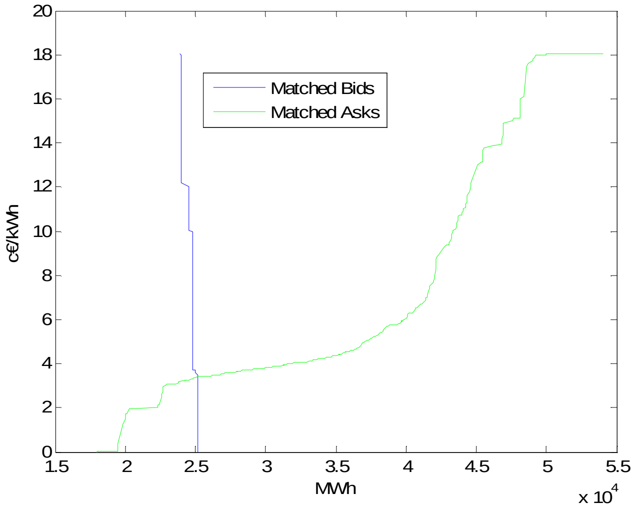

Figure 4.3 – Bid-ask curve of the first EP calculation (17th hour of 24/03/2009).

This first match with orders from both countries would lead to a market price, MP_1, of 3.395 c€/kWh[29], as it can be witnessed in Figure 4.3. However, the interconnection flow, IF, that would result from this match is -2161.4 MWh, which exceeds the NTC[30] in that period. The reason why the IF assumes a negative value in this case is because the cross-border flow is from Spain to Portugal, what means that the purchase orders in the Portuguese area exceed the selling ones. In other words, Portugal plays the role of the importing area in this hour.

Consequently, there is the need of splitting the initial single market in two separate markets: one regarding the Spanish orders and the other concerning the Portuguese ones. Figures 4.4 and 4.5 illustrate the result of this computation.

[29] It is relevant to mention at this point that OMEL does not publish the unconstrained price when the two markets are splitted.
[30] The NTC in this particular hour was 1200 MWh for the flow Spain-Portugal.

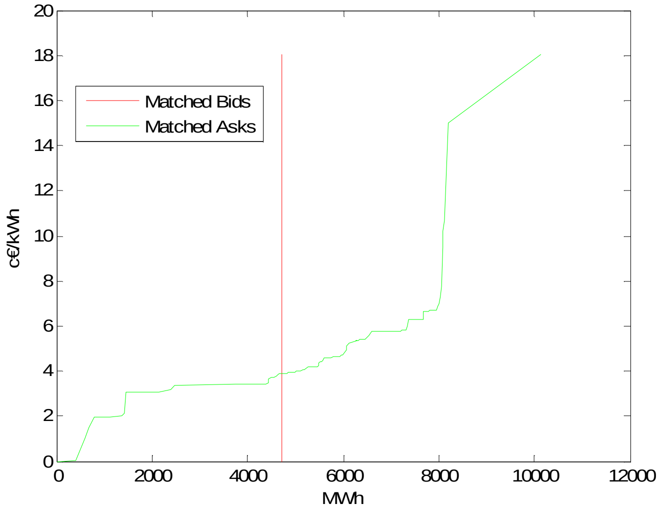

Figure 4.4 – Bid-ask curve of the Portuguese area (17th hour of 24/03/2009).

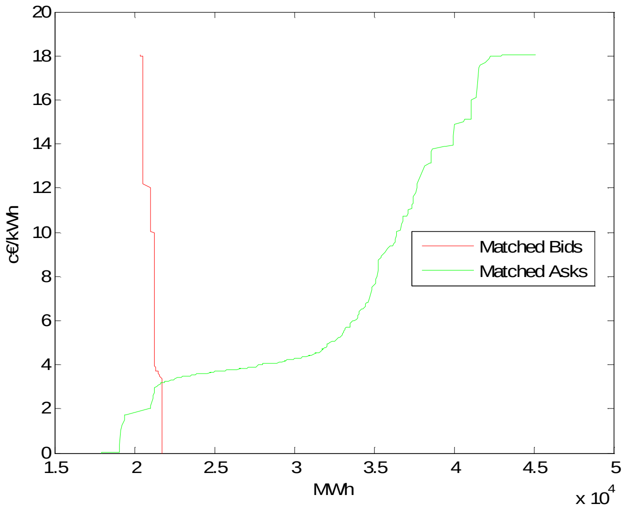

Figure 4.5 – Bid-ask curve of the Spanish area (17th hour of 24/03/2009).

The computation of the EP algorithm in both areas produced the following results, which can be verified in Figures 4.4 and 4.5:

- Market price of the Portuguese area, MP_{PT} = 3.917 c€/kWh;
- Market price of the Spanish area, MP_{SP} = 3.200 c€/kWh;
- Tradable volume in the Portuguese area at MP_{PT}, TV_{PT} = 4711.4 MWh;
- Tradable volume in the Spanish area at MP_{SP}, TV_{SP} = 21716 MWh.

These results are supported by OMEL's aggregated supply and demand curves for each area, Figures 4.6 and 4.7.

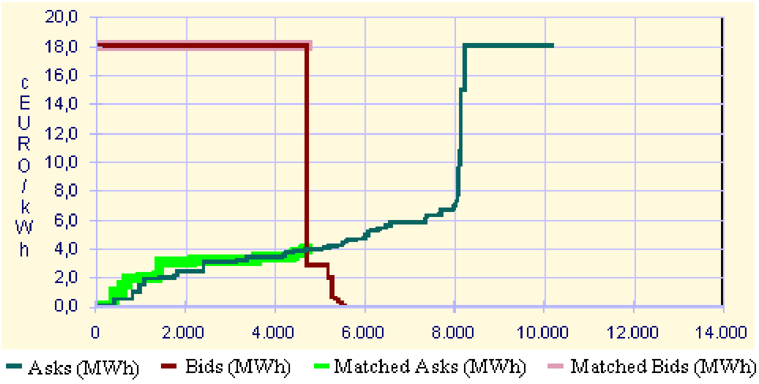

Figure 4.6 – OMEL's bid-ask curve of the Portuguese area (17th hour of 24/03/2009).

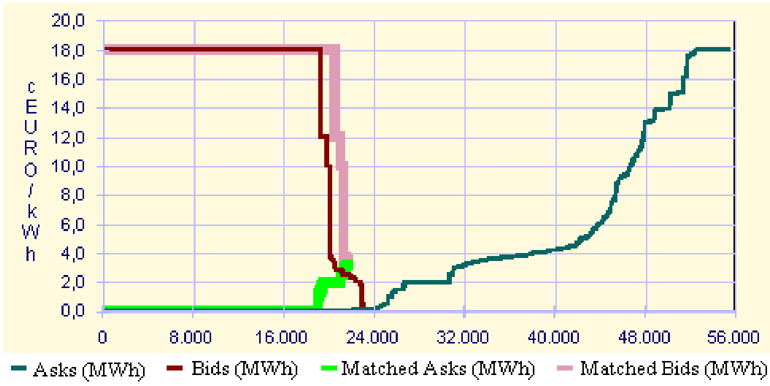

Figure 4.7 – OMEL's bid-ask curve of the Spanish area (17th hour of 24/03/2009).

All in all, we reach the conclusion that splitting the initial market into two separate areas has increased the market price in Portugal. Initially, the market price was MP_1 = 3.395 c€/kWh, equal in both countries. After the separation the marginal price in the Portuguese area raised to MP_{PT} = 3.917 c€/kWh. The explanation for this phenomenon is the following: before market splitting, Portugal was importing 2161 MWh, approximately, from Spain. However, that value exceeded the NTC and was reduced to 1200 MWh. As a consequence, the extra 961 MWh[31] that Portugal was importing from Spain needed to be produced by Portuguese generating units, at a higher price than the Spanish ones, thus increasing the marginal price in Portugal.

On the other hand, from the Spanish point of view, this occurrence can be interpreted has a decrease of 961 MWh in demand. As a result, the costly generating units were ordered to regulate down, or even to shut down, by the SO, leading to a decrease in the Spanish marginal price, MP_{SP}, when compared to MP_1.

4.2 Wind farm in a market environment

In this section it will be shown the results of the algorithm described in chapter 3, regarding the financial income of a particular wind unit attending the power market. The results are divided according to the two wind forecasts methods employed, already referred in the previous sections. To end this section, the results obtained are discussed.

[31] This value results from the difference between the IF before, 2161 MWh, and after, 1200 MWh, the separation in two areas.

4.2.1 Wind farm characteristics

The wind farm used in this study has the characteristics outlined in Table 4.1.

Table 4.1 – Wind farm data.

Maximum Power	96.614 MW
Limit Power	96.614 MVA
Installed Power	114 MW
Number of Wind Turbines	38
Wind Turbine Power	3 MW
Manufacturer	VESTAS
Model	V90

4.2.2 Data acquisition/ Simulation features

In order to draw some conclusions concerning the introduction of the wind farm characterized in the previous section in the power market, six scenarios were built, in order to assess the influence of the main variables on the overall economic outcome of such an approach. Those scenarios correspond to the six data bases (DB1, DB2, DB3, DB4, DB5 and DB6) referred to in Table 4.2:

- All scenarios have the same day-ahead generation schedule and actual generation.
- DB1, DB2 and DB3 have in common the same intraday scheduling methodology, based on NWP forecasts.
- DB4, DB5 and DB6 have in common the same intraday scheduling methodology, based on ARMA forecasts.
- For each of the group scenarios referred (DB1, DB2, DB3 and DB4, DB5, DB6) variations were made on prices by using: exclusive Portuguese values (DB1, DB4), exclusive Spanish values (DB3, DB6) and a mix of Portuguese values complemented by Spanish values for intraday prices when there was no such price available in Portugal (DB2, DB5).

In order to run the simulation the following information was gathered, for the whole year of 2008 and in an hourly basis:

- Day-ahead generation schedule (DAS), provided by REN (based on NWP models);
- Day-ahead market prices of Portugal (DAP_{PT}) and Spain (DAP_{SP}), granted by OMEL;
- Intraday generation schedules, based on NWP methods (IDS_{NWP}) and on ARMA (IDS_{ARMA}) models;
- Intraday prices of Portugal (IDP_{PT}) and Spain (IDP_{SP}), provided by OMEL;
- Actual Generation (AG) of the wind farm, made available by REN;
- Balancing prices of Portugal (BP_{PT}): upwards (BPU_{PT}) and downwards(BPD_{PT}), provided by REN;

- Balancing prices of Spain (BP_{SP}): upwards (BPU_{SP}) and downwards (BPD_{SP}), made available by REE.

The above information was processed in the form of 6 data bases, which are highlighted in Table 4.2.

Table 4.2 – Contents of the different data bases created.

Data Base (DB) \ Contents	DAS (MW)	DAP_{PT} (€/MWh)	DAP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	IDP_{SP} (€/MWh)	IDP_{PT+SP} (€/MWh)	AG (MW)	BPD_{PT} (€/MWh)	BPD_{SP} (€/MWh)	BPU_{PT} (€/MWh)	BPU_{SP} (€/MWh)
DB1	x	x		x		x			x	x		x	
DB2	x	x		x				x	x	x		x	
DB3	x		x	x			x		x		x		x
DB4	x	x			x	x			x	x		x	
DB5	x	x			x			x	x	x		x	
DB6	x		x		x		x		x		x		x

As one may notice, in Table 4.2 there is an acronym, IDP_{PT+SP}, that was not mentioned until this point in the work. The IDP_{PT+SP} arose from lack of liquidity of the Portuguese intraday (ID) market in the year of 2008. Indeed, as one may witness in further sections, there were many hours in the different ID sessions of that year with no ID price, due to the nonexistence of both selling and buying orders that could be matched. Therefore, the IDP_{PT+SP} integrates in the hours which the IDP_{PT} is not defined, the prices of the correspondent intraday sessions of the Spanish area.

Each data base is composed by 8784 values of the correspondent contents (Table 4.2). This happens because, as it was previously notified, the information was gathered in an hourly basis and 2008 was a leap year.

After having described the scenarios considered in the simulation, let us consider now the different strategies implemented. For each hour of each data base it is determined the revenue of the wind producer in three hypothetic situations:

1. All the actual generation (AG) of the wind farm is injected in the transmission grid and priced at day-ahead market price (DAP). This means that there are no deviations;
2. The wind producer does not correct the day-ahead schedule (DAS) in the ID market, what implies that he exposes the difference between the AG and the DAS to the balancing prices of the system operator (SO);
3. The wind producer corrects each hour of the DAS in the ID market only once and in the last available ID session, exposing the difference between the AG and the correction in the ID market, named intraday schedule (IDS), to the balancing prices of the SO.

Theoretically, analysing the three situations we conclude that in the first one the wind producer will have the highest revenue and in the second one the lowest financial income, with the revenue in the third case being placed between those limits. As a result, let us denominate the first situation the upper limit, UL, and the second one the lower limit, LL.

The revenue of the wind producer in the UL situation, R_{UL}, can be determined using (4.1).

$$R_{UL} = (AG \times DAP) \tag{4.1}$$

In the LL situation, the revenue of the wind producer, R_{LL} is calculated according to (4.2).

$$R_{LL} = (DAS \times DAP) + \{(AG - DAS) \times BP\} \tag{4.2}$$

In (4.2) if the difference between AG and DAS is positive it is used the BPD. On the opposite, in case the same difference assumes a negative value it is used the BPU.

Let us denominate the third case the intraday (ID) situation, since it is the sole one in which the wind producer participates in the ID market. The financial income of the wind producer in this case, R_{ID}, is determined according to (4.3)[32].

$$R_{ID} = (DAS \times DAP) + \{(IDS - DAS) \times IDP\} + \{(AG - IDS) \times BP\} \tag{4.3}$$

As it was pointed out, R_{UL}, R_{LL} and R_{ID} are hourly revenues. To reach the correspondent yearly revenues, YR_{UL}, YR_{LL} and YR_{ID}, it is necessary to sum the 8784 revenues that derive from the hourly application of (4.1) (4.2) and (4.3).

The presentation of the results of the six data bases will be divided according to the forecast methodology that was employed to make the corrections in the ID sessions. Consequently, in section 4.2.3 it will be shown the results of DB1, DB2 and DB3. In section 4.2.4, the outcome of DB4, DB5 and DB6 is illustrated.

Last but not least, in section 4.2.5, the predictions in the ID sessions are bettered and it is evaluated the impact of that improvement on the revenue of the wind producer.

4.2.3 Results using NWP forecasts (DB1, DB2 and DB3)

In this section it will be presented the results of the data bases that make use of the NWP models to operate the adjustments in ID sessions. The methodology applied to match the NWP forecasts (provided by REN) with the intraday sessions is explained in Appendix C. Basically, that methodology is based in the philosophy that only one correction is performed for each hour in the last available ID session, with the last accessible information.

4.2.3.1 DB1

Figure 4.8 shows the actual generation of the wind farm during the 8784 hours of 2008.

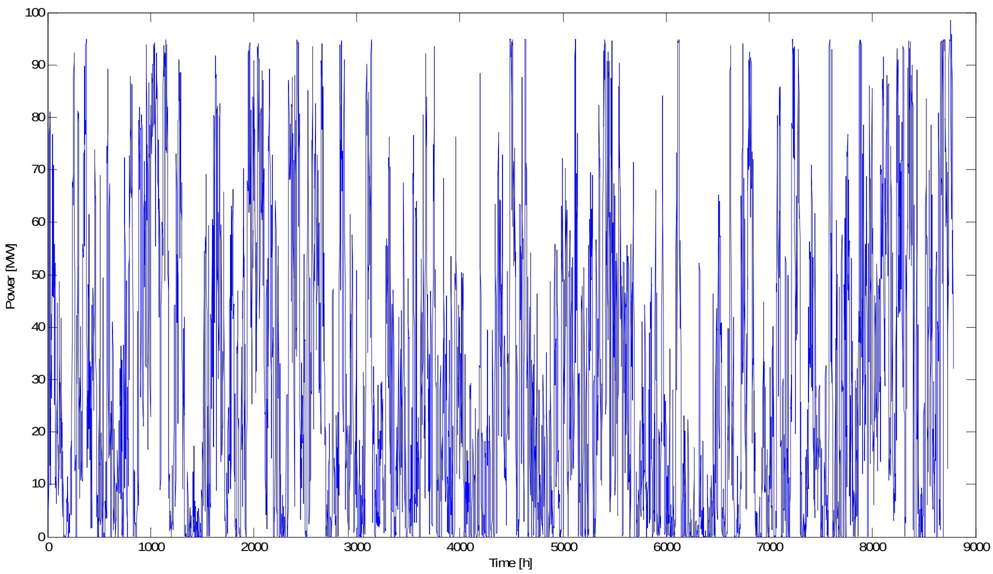

Figure 4.8 – Actual generation of the studied wind farm in the year of 2008.

[32] This equation is equal to (3.15).

As one can witness in Table 4.2, this AG is common to all six data bases. The total generation of the wind farm in the year of 2008 was 264.9 GWh.

Tables 4.3 and 4.4 demonstrate the calculation of R_{UL}, R_{LL} and R_{ID} for two particular days of 2008, according to the features of DB1.

Table 4.3 – DB1 – results of R_{UL}, R_{LL} and R_{ID} for 27/04/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
27/04/08	1	5.6475	56.69	-1	-1	5.0725	47.92	-1	-1	-1	-1	16.94	43.7	69.7	960.3	813.6	811.2
27/04/08	2	5.31	54.53	-1	-1	5.685	46	-1	-1	-1	-1	15.94	44.6	64.5	869.2	763.7	764.2
27/04/08	3	5.3625	56.69	-1	-1	3.095	44.46	-1	-1	-1	-1	11.64	30.6	82.7	659.9	496.1	464.7
27/04/08	4	6.0025	57.62	-1	-1	4.0375	49.71	-1	-1	-1	-1	14.01	34.3	81.0	807.3	620.5	590.2
27/04/08	5	4.7875	54.61	-1	-1	-1	49.81	3.4175	-1	-1	-1	13.65	6.7	102.5	745.4	320.8	320.8
27/04/08	6	4.2075	54.6	-1	-1	-1	49.81	0.1975	-1	-1	-1	13.89	48.5	60.7	758.4	699.3	699.3
27/04/08	7	0.405	54.5	-1	-1	-1	51	4.5325	-1	-1	-1	7.67	36.6	72.4	418.0	288.0	288.0
27/04/08	8	0.7	53.77	-1	-1	-1	44.38	0.435	-1	-1	-1	3.24	13.7	93.9	174.2	72.4	72.4
27/04/08	9	2.5825	53.68	-1	-1	-1	44.71	0	-1	-1	-1	23.73	30.7	76.7	1273.8	787.9	787.9
27/04/08	10	2.4325	55	-1	-1	-1	52.5	0.985	-1	-1	-1	13.39	29.5	80.5	736.5	457.0	457.0
27/04/08	11	3.0975	56.75	-1	-1	-1	51.75	4.4075	-1	-1	-1	0.03	64.8	48.7	1.7	26.4	26.4
27/04/08	12	3.5925	57.48	-1	-1	-1	54	-1	-1	7.0225	-1	0.71	62.6	52.3	40.8	55.7	55.7
27/04/08	13	7.16	58.04	-1	-1	-1	53.04	-1	-1	23.64	-1	2.05	49.5	66.6	119.0	75.2	75.2
27/04/08	14	13.998	58.87	-1	-1	-1	55.37	-1	-1	11.8375	-1	6.75	43.8	73.9	397.4	288.4	288.4
27/04/08	15	23.305	57.61	-1	-1	-1	52.61	-1	-1	16.62	-1	13.71	46.3	68.9	789.8	681.5	681.5
27/04/08	16	38.425	55.29	-1	-1	-1	50.29	-1	-1	21.45	-1	7.95	35.2	75.4	439.6	-173.3	-173.3
27/04/08	17	50.61	54.43	-1	-1	-1	48.6	-1	-1	23.64	-1	16.18	45.8	63.0	880.7	585.6	585.6
27/04/08	18	49.613	53.31	-1	-1	-1	46	-1	-1	24.715	-1	13.63	35.6	71.0	726.6	90.1	90.1
27/04/08	19	43.56	53.69	-1	-1	-1	46	-1	-1	28.345	-1	16.95	47.7	59.7	910.0	750.1	750.1
27/04/08	20	39.815	54.53	-1	-1	-1	50.5	-1	-1	34.0675	-1	27.15	35.0	74.1	1480.5	1232.6	1232.6
27/04/08	21	34.178	54.69	34.12	-1	-1	49.2	-1	-1	-1	-1	27.42	43.7	65.7	1499.6	1425.2	1425.2
27/04/08	22	29.14	68.89	34.225	-1	-1	62	-1	-1	-1	-1	37.85	47.5	90.3	2607.5	2421.2	2421.2
27/04/08	23	24.885	64.75	34.605	-1	-1	58.28	-1	-1	-1	-1	49.75	37.1	92.4	3221.3	2533.8	2533.8
27/04/08	24	26.713	57.6	34.19	-1	-1	52.6	-1	-1	-1	-1	56.38	45.3	69.9	3247.5	2882.6	2882.6

Table 4.4 – DB1 – results of R_{UL}, R_{LL} and R_{ID} for 12/11/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
12/11/08	1	48.9275	80.88	-1	-1	35.68	-1	-1	-1	-1	-1	94.78	79.9	81.9	7665.8	7620.9	7620.9
12/11/08	2	48.4125	76	-1	-1	34.6375	-1	-1	-1	-1	-1	94.79	46.7	105.3	7204.0	5845.2	5845.2
12/11/08	3	45.3275	75.92	-1	-1	33.9825	-1	-1	-1	-1	-1	94.71	52.6	99.3	7190.4	6038.8	6038.8
12/11/08	4	40.515	65.48	-1	-1	36.2175	-1	-1	-1	-1	-1	91.24	68.8	62.1	5974.4	6142.8	6142.8
12/11/08	5	38.315	65.03	-1	-1	-1	-1	42.875	-1	-1	-1	91.41	58.3	71.8	5944.4	5587.1	5587.1
12/11/08	6	31.0975	65.14	-1	-1	-1	65.14	42.6825	-1	-1	-1	94.75	53.0	77.3	6172.0	5399.3	5399.3
12/11/08	7	24.285	65.15	-1	-1	-1	-1	39.2275	-1	-1	-1	94.72	47.7	82.6	6171.0	4941.9	4941.9
12/11/08	8	28.6825	79.8	-1	-1	-1	85.79	36.21	-1	-1	-1	92.6	62.7	96.9	7389.5	6296.5	6296.5
12/11/08	9	29.79	79.4	-1	-1	-1	79.4	30.84	-1	-1	-1	67.34	48.7	110.1	5346.8	4194.0	4194.0
12/11/08	10	32.665	80.93	-1	-1	-1	80.93	29.07	-1	-1	-1	49.74	63.1	98.8	4025.5	3721.0	3721.0
12/11/08	11	32.4675	79.3	-1	-1	-1	79.3	47.8225	67.080	-1	-1	51.99	71.3	87.3	4122.8	3966.6	3901.8
12/11/08	12	10.8	81.02	-1	-1	-1	81.02	-1	70.010	53.9675	66.58	57.38	74.6	87.5	4648.9	4349.9	4003.7
12/11/08	13	8.265	80.99	-1	-1	-1	80.99	-1	63.070	45.645	63.07	57.93	69.8	92.2	4691.8	4136.0	3884.4
12/11/08	14	14.2875	80.88	-1	-1	-1	80.88	-1	59.510	41.7075	63.52	52.72	40.2	121.6	4264.0	2700.6	3340.0
12/11/08	15	10.175	80.2	-1	-1	-1	80.2	-1	61.170	32.2275	58.14	33.43	42.5	117.9	2681.1	1804.4	2149.3
12/11/08	16	10.83	80.94	-1	-1	-1	80.94	-1	61.170	20.405	-1	38.47	69.0	92.9	3113.8	2783.7	2783.7
12/11/08	17	16.03	80.87	-1	-1	-1	80.87	-1	63.520	12.9275	-1	40.87	72.3	89.4	3305.2	3092.3	3092.3
12/11/08	18	15.1275	80.96	-1	-1	-1	80.96	-1	63.160	11.94	-1	35.36	113.2	48.8	2862.7	3515.0	3515.0
12/11/08	19	15.225	83.23	-1	-1	-1	80.32	-1	79.800	13.6725	-1	29.47	78.0	88.4	2452.8	2378.3	2378.3
12/11/08	20	17.9475	87.84	-1	-1	-1	84.77	-1	86.040	14.1	-1	34.4	63.4	112.3	3021.7	2619.6	2619.6
12/11/08	21	13.7075	85.01	5.915	85.01	-1	82.9	-1	83.210	-1	-1	34.04	93.9	76.1	2893.7	3074.5	3143.8
12/11/08	22	11.2	81.96	5.9075	81.96	-1	81.96	-1	67.000	-1	-1	45.18	80.4	83.5	3703.0	3649.9	3641.7
12/11/08	23	18.9725	81.33	6.725	81.33	-1	81.33	-1	-1	-1	-1	68.99	74.4	88.3	5611.0	5264.3	5179.5
12/11/08	24	29.8225	81.13	8.335	81.13	-1	81.13	-1	-1	-1	-1	87.09	82.8	79.5	7065.6	7161.2	7197.1

As we can observe by the presence of multiple -1 in the columns of the IDP_{PT} in Tables 4.3 and 4.4, there were many non-priced ID sessions in the year of 2008. Note that replacing the -1 by zero would not even be an option, because zero could perfectly be a price of an intraday session. The negative value denotes that there was not any match between bids and asks in that particular session.

Indeed, in DB1, only 3176 hours had ID prices[33]. This means that over 63% of the 8784 hours were filled with -1 in the columns concerning the IDP_{PT}. Such fact became the motivation for the building of DB2, which has only one difference in relation with DB1: the 5608 hours that are filled with -1 are replaced by the correspondent ID prices of the Spanish sessions, IDP_{SP}.

Moreover, as it demonstrated in Tables 4.3 and 4.4, the R_{ID} equals the R_{LL} in the hours that are characterized by the non-existence of ID market prices. With the impossibility of correcting the day-ahead schedule (DAS) in the ID sessions, the wind producer has to expose the difference between the actual generation (AG) and the DAS to the SO balancing prices, which is identical to the LL situation, (4.2). Consequently, in DB1 there are 5608 hours in which $R_{ID} = R_{LL}$. In the other 3176 hours, the R_{ID} exceeds the R_{LL} in all cases where the adjustments in the ID sessions are performed in order to reduce the initial difference between the AG and the DAS, like what happens, for instance, with hour 14 of Table 4.4. To these adjustments, let us denominate them corrections in the direction of AG. In contrast, if the adjustment is executed in such way that does not minimize the original unbalance between the AG and the DAS, the R_{LL} will of course exceed the R_{ID}. In these occasions, we rapidly come to the conclusion that the wind producer would better not participate in the ID markets because, the huge advantage of the ID sessions is, precisely, permitting to correct the first prediction made in the day-ahead market. By using the term 'correct', we mean reducing the difference between the AG and the DAS in the ID market, not enlarging it, as in hours 1, 3 and 4 of Table 4.3. Of course this reasoning is very straightforward after the fact, i.e. after knowing both the DAS and the AG. The sole problem is that when the generator has to take a decision he only knows the past (DAS), not the future (AG). The only thing he knows is that the forecast that he is using for the intraday session has a high probability of being more accurate than the one used for the DAS.

Just like what happens with the columns of the IDP_{PT}, there are also several -1 in the IDS_{NWP} columns. Still, these -1 have a different connotation. They are placed, in each hour, in the columns in which the DAS is not corrected. Since, according to the implemented algorithm, it is only made one correction to the DAS in the ID markets, for each individual hour (line) considered there is only one IDS_{NWP} column that has a value different from -1, corresponding exactly to the ID session that was chosen to adjust the DAS.

Furthermore, it is also natural in both Tables that, generally, the BPU is higher than the DAP and the BPD lower than the same DAP. Those differences imply a penalization if the wind producer does not make accurate forecasts in order to reach a schedule as close to the AG as possible, namely by participating cautiously in the ID sessions. If the IDS exceeds the AG, he is penalized for not producing the amount he declared in the ID session, paying the difference between the IDS and the AG at BPU. On the opposite, in the case the AG being higher than the IDS the wind producer is penalised for not selling the quantity corresponding to the difference between the AG and the IDS at a price higher than BPD (day-ahead market price for example or even intraday price).

Drawing attention to the financial revenue of the wind producer, it is clear that the hourly revenues in Table 4.4 exceed the ones in Table 4.3. This happens mainly because the wind farm generated more power in 12/11/2008 than in 27/04/2008. In fact, there was not any hour in 27/04/2008 that surpassed the correspondent hour in 12/11/2008 in terms of AG. In addition, it is also patent in both Tables that the R_{UL} exceeds, in general, both the R_{LL} and the R_{ID}, as it was expected. Nevertheless, in hours 11 and 12 of 27/04/2008 that was not verified because the BPU in those two hours was lower than the correspondent day-ahead market price. Therefore, there was no

[33] According to the distribution of the generation schedules for the different ID sessions employed in the computed algorithm.

penalisation for the wind producer not having produced what he previously declared in the IDS and even allowed the R_{LL} and the R_{ID} to exceed the R_{UL}. These, of course are singular cases that happen very rarely.

Figure 4.9 shows the yearly revenues of the wind producer in the three referred situations, obtained with the contents of DB1.

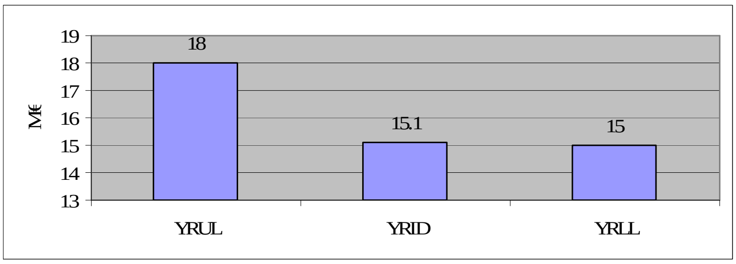

Figure 4.9 – YR_{UL}, YR_{ID} and YR_{LL} obtained with the features of DB1.

4.2.3.2 DB2

This data base is characterized by introducing the prices of the ID Spanish sessions in the correspondent Portuguese ID sessions that had no price defined in DB1.

Tables 4.5 and 4.6 demonstrate the calculation of the hourly revenues of the wind producer in the upper limit, lower limit and intraday situations (R_{UL}, R_{LL} and R_{ID}) in the same two days reported in Tables 4.3 and 4.4.

Table 4.5 – DB2 – results of R_{UL}, R_{LL} and R_{ID} for 27/04/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
27/04/08	1	5.6475	56.69	-1	-1	5.0725	47.92	-1	-1	-1	-1	16.94	43.7	69.7	960.3	813.6	811.2
27/04/08	2	5.31	54.53	-1	-1	5.685	46	-1	-1	-1	-1	15.94	44.6	64.5	869.2	763.7	764.2
27/04/08	3	5.3625	56.69	-1	-1	3.095	44.46	-1	-1	-1	-1	11.64	30.6	82.7	659.9	496.1	464.7
27/04/08	4	6.0025	57.62	-1	-1	4.0375	49.71	-1	-1	-1	-1	14.01	34.3	81.0	807.3	620.5	590.2
27/04/08	5	4.7875	54.61	-1	-1	-1	49.81	3.4175	49.98	-1	-1	13.65	6.7	102.5	745.4	320.8	261.5
27/04/08	6	4.2075	54.6	-1	-1	-1	49.81	0.1975	49.71	-1	-1	13.89	48.5	60.7	758.4	699.3	694.5
27/04/08	7	0.405	54.5	-1	-1	-1	51	4.5325	50.27	-1	-1	7.67	36.6	72.4	418.0	288.0	344.4
27/04/08	8	0.7	53.77	-1	-1	-1	44.38	0.435	44.38	-1	-1	3.24	13.7	93.9	174.2	72.4	64.3
27/04/08	9	2.5825	53.68	-1	-1	-1	44.71	0	45.71	-1	-1	23.73	30.7	76.7	1273.8	787.9	749.1
27/04/08	10	2.4325	55	-1	-1	-1	52.5	0.985	50	-1	-1	13.39	29.5	80.5	736.5	457.0	427.4
27/04/08	11	3.0975	56.75	-1	-1	-1	51.75	4.4075	56.18	-1	-1	0.03	64.8	48.7	1.7	26.4	36.2
27/04/08	12	3.5925	57.48	-1	-1	-1	54	-1	57	5.405	51.73	0.71	62.6	52.3	40.8	55.7	54.7
27/04/08	13	7.16	58.04	-1	-1	-1	53.04	-1	53.04	7.0225	49.33	2.05	49.5	66.6	119.0	75.2	77.6
27/04/08	14	13.998	58.87	-1	-1	-1	55.37	-1	58.04	11.8375	52.98	6.75	43.8	73.9	397.4	288.4	333.6
27/04/08	15	23.305	57.61	-1	-1	-1	52.61	-1	52.61	16.62	51.85	13.71	46.3	68.9	789.8	681.5	795.5
27/04/08	16	38.425	55.29	-1	-1	-1	50.29	-1	50.29	21.45	55.29	7.95	35.2	75.4	439.6	-173.3	168.1
27/04/08	17	50.61	54.43	-1	-1	-1	48.6	-1	55.01	23.64	56.5	16.18	45.8	63.0	880.7	585.6	760.9
27/04/08	18	49.613	53.31	-1	-1	-1	46	-1	50.1	24.715	53	13.63	35.6	71.0	726.6	90.1	538.2
27/04/08	19	43.56	53.69	-1	-1	-1	46	-1	50	28.345	54	16.95	47.7	59.7	910.0	750.1	836.8
27/04/08	20	39.815	54.53	-1	-1	-1	50.5	-1	55.74	34.0675	55.74	27.15	35.0	74.1	1480.5	1232.6	1338.2
27/04/08	21	34.178	54.69	34.12	48.78	-1	49.2	-1	56.89	-1	54.2	27.42	43.7	65.7	1499.6	1425.2	1426.2
27/04/08	22	29.14	68.89	34.225	57.5	-1	62	-1	56.97	-1	52.18	37.85	47.5	90.3	2607.5	2421.2	2472.0
27/04/08	23	24.885	64.75	34.605	55.04	-1	58.28	-1	56.75	-1	52	49.75	37.1	92.4	3221.3	2533.8	2708.2
27/04/08	24	26.713	57.6	34.19	41.35	-1	52.6	-1	49.6	-1	50	56.38	45.3	69.9	3247.5	2882.6	2853.0

Table 4.6 – DB2 – results of R_{UL}, R_{LL} and R_{ID} for 12/11/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{PT+SP} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
12/11/08	1	48.9275	80.88	-1	-1	35.68	59.6	-1	-1	-1	-1	94.78	79.9	81.9	7665.8	7620.9	7889.8
12/11/08	2	48.4125	76	-1	-1	34.6375	59.5	-1	-1	-1	-1	94.79	46.7	105.3	7204.0	5845.2	5668.9
12/11/08	3	45.3275	75.92	-1	-1	33.9825	54.25	-1	-1	-1	-1	94.71	52.6	99.3	7190.4	6038.8	6020.1
12/11/08	4	40.515	65.48	-1	-1	36.2175	53.88	-1	-1	-1	-1	91.24	68.8	62.1	5974.4	6142.8	6206.9
12/11/08	5	38.315	65.03	-1	-1	-1	49.72	42.875	49.52	-1	-1	91.41	58.3	71.8	5944.4	5587.1	5547.0
12/11/08	6	31.0975	65.14	-1	-1	-1	65.14	42.6825	49.17	-1	-1	94.75	53.0	77.3	6172.0	5399.3	5354.9
12/11/08	7	24.285	65.15	-1	-1	-1	60	39.2275	55.5	-1	-1	94.72	47.7	82.6	6171.0	4941.9	5058.5
12/11/08	8	28.6825	79.8	-1	-1	-1	85.79	36.21	62.9	-1	-1	92.6	62.7	96.9	7389.5	6296.5	6298.0
12/11/08	9	29.79	79.4	-1	-1	-1	79.4	30.84	66.49	-1	-1	67.34	48.7	110.1	5346.8	4194.0	4212.7
12/11/08	10	32.665	80.93	-1	-1	-1	80.93	29.07	67.54	-1	-1	49.74	63.1	98.8	4025.5	3721.0	3705.0
12/11/08	11	32.4675	79.3	-1	-1	-1	79.3	47.8225	67.08	-1	-1	51.99	71.3	87.3	4122.8	3966.6	3901.8
12/11/08	12	10.8	81.02	-1	-1	-1	81.02	-1	70.01	53.9675	66.58	57.38	74.6	87.5	4648.9	4349.9	4003.7
12/11/08	13	8.265	80.99	-1	-1	-1	80.99	-1	63.07	45.645	63.07	57.93	69.8	92.2	4691.8	4136.0	3884.4
12/11/08	14	14.2875	80.88	-1	-1	-1	80.88	-1	59.51	41.7075	63.52	52.72	40.2	121.6	4264.0	2700.6	3340.0
12/11/08	15	10.175	80.2	-1	-1	-1	80.2	-1	61.17	32.2275	58.14	33.43	42.5	117.9	2681.1	1804.4	2149.3
12/11/08	16	10.83	80.94	-1	-1	-1	80.94	-1	61.17	20.405	64.52	38.47	69.0	92.9	3113.8	2783.7	2740.8
12/11/08	17	16.03	80.87	-1	-1	-1	80.87	-1	63.52	12.9275	65.02	40.87	72.3	89.4	3305.2	3092.3	3114.9
12/11/08	18	15.1275	80.96	-1	-1	-1	80.96	-1	63.16	11.94	65.44	35.36	113.2	48.8	2862.7	3515.0	3667.3
12/11/08	19	15.225	83.23	-1	-1	-1	80.32	-1	79.8	13.6725	83.23	29.47	78.0	88.4	2452.8	2378.3	2370.2
12/11/08	20	17.9475	87.84	-1	-1	-1	84.77	-1	86.04	14.1	87.84	34.4	63.4	112.3	3021.7	2619.6	2525.6
12/11/08	21	13.7075	85.01	5.915	85.01	-1	82.9	-1	83.21	-1	85.01	34.04	93.9	76.1	2893.7	3074.5	3143.8
12/11/08	22	11.2	81.96	5.9075	81.96	-1	81.96	-1	67	-1	65.58	45.18	80.4	83.5	3703.0	3649.9	3641.7
12/11/08	23	18.9725	81.33	6.725	81.33	-1	81.33	-1	64.7	-1	64.52	68.99	74.4	88.3	5611.0	5264.3	5179.5
12/11/08	24	29.8225	81.13	8.335	81.13	-1	81.13	-1	63.52	-1	63.52	87.09	82.8	79.5	7065.6	7161.2	7197.1

In Tables 4.5 and 4.6, the hours filled with -1 in the IDP_{PT+SP} column mean that they are not covered by that particular ID session.

From the inspection of Tables, 4.5 and 4.6, one can observe that, with prices in all ID sessions, the R_{LL} and the R_{ID} have distinct values, in the majority of the cases. Additionally, in these two Tables it is also evident the impact that a good or bad correction of the day-ahead schedule (DAS) in the ID markets has on the revenue of the wind producer. For instance, in hour 16 of Table 4.5, the R_{ID} exceeded the R_{LL} in more than 340 € and in hour 14 of Table 4.6, the difference between both revenues was 640 €, in favour of the R_{ID}. In these two situations, the ID market was used to reduce the preliminary difference between the DAS and the actual generation (AG) and when that happens, the wind producer profits from it. However, when the adjustments are executed in such way that enlarge the initial difference between the DAS and the AG, the wind producer faces a loss in the R_{ID}, in comparison with the R_{LL}.

Figures 4.10 and 4.11 illustrate the DAS, IDS and AG in 27/042008 and 12/11/2008.

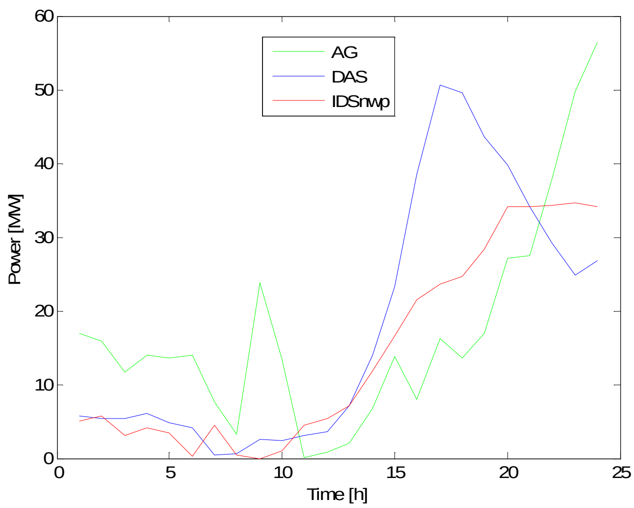

Figure 4.10 – DAS, IDS_{NWP} and AG in 27/04/2008.

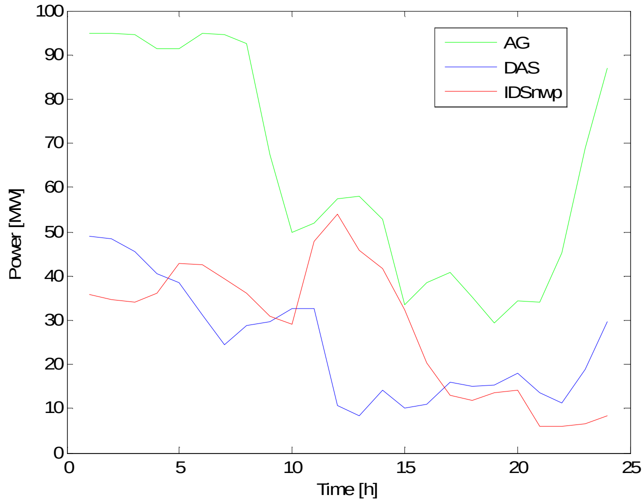

Figure 4.11 – DAS, IDS$_{NWP}$ and AG in 12/11/2008.

Analysing both Figures, 4.10 and 4.11, we can conclude that the wind producer profits from participating in the ID sessions when the intraday schedule (IDS) curve is situated between the curves of the AG and the DAS. As a matter of fact, if that happens, there is a minimization of unbalance between AG and DAS, which is the main purpose of the ID markets.

Figure 4.12 shows the yearly revenues of the wind producer in the upper limit, lower limit and intraday situations (YR$_{UL}$, YR$_{LL}$ and YR$_{ID}$), calculated with the contents of DB2.

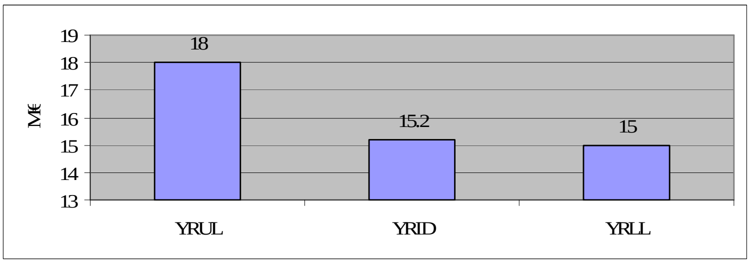

Figure 4.12 – YR$_{UL}$, YR$_{ID}$ and YR$_{LL}$ obtained with the features of DB2.

4.2.3.3 DB3

In this data base it were used the prices of the Spanish area in all market sessions, and also in the balancing prices. Tables 4.7 and 4.8 show the results for the same two days that were portrayed in the previous two sections.

Table 4.7 – DB3 – results of R_{UL}, R_{LL} and R_{ID} for 27/04/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	(MW)	BPD_{SP} (€/MWh)	BPU_{SP} (€/MWh)	(€)	(€)	(€)
27/04/08	1	5.6475	51.92	-1	-1	5.0725	47.92	-1	-1	-1	-1	16.94	51.92	52.24	879.5	879.5	881.8
27/04/08	2	5.31	49	-1	-1	5.685	46	-1	-1	-1	-1	15.94	49.00	53.63	781.1	781.1	779.9
27/04/08	3	5.3625	44.46	-1	-1	3.095	44.46	-1	-1	-1	-1	11.64	44.46	54.94	517.5	517.5	517.5
27/04/08	4	6.0025	49.71	-1	-1	4.0375	49.71	-1	-1	-1	-1	14.01	49.71	56.82	696.4	696.4	696.4
27/04/08	5	4.7875	49.71	-1	-1	-1	49.81	3.4175	49.98	-1	-1	13.65	49.71	57.08	678.5	678.5	678.2
27/04/08	6	4.2075	49.71	-1	-1	-1	49.81	0.1975	49.71	-1	-1	13.89	49.71	55.43	690.5	690.5	690.5
27/04/08	7	0.405	50	-1	-1	-1	51	4.5325	50.27	-1	-1	7.67	50.00	54.97	383.5	383.5	384.6
27/04/08	8	0.7	49.38	-1	-1	-1	44.38	0.435	44.38	-1	-1	3.24	38.91	49.38	160.0	133.4	131.9
27/04/08	9	2.5825	49.71	-1	-1	-1	44.71	0	45.71	-1	-1	23.73	49.71	55.34	1179.6	1179.6	1189.9
27/04/08	10	2.4325	55	-1	-1	-1	52.5	0.985	50	-1	-1	13.39	55.00	58.15	736.5	736.5	743.7
27/04/08	11	3.0975	56.75	-1	-1	-1	51.75	4.4075	56.18	-1	-1	0.03	56.75	56.75	1.7	1.7	1.0
27/04/08	12	3.5925	57.48	-1	-1	-1	54	-1	57	5.405	51.73	0.71	57.48	57.48	40.8	40.8	30.4
27/04/08	13	7.16	58.04	-1	-1	-1	53.04	-1	53.04	7.0225	49.33	2.05	42.50	58.04	119.0	119.0	120.2
27/04/08	14	13.9975	58.87	-1	-1	-1	55.37	-1	58.04	11.8375	52.98	6.75	44.62	58.87	397.4	397.4	410.1
27/04/08	15	23.305	57.61	-1	-1	-1	52.61	-1	52.61	16.62	51.85	13.71	42.74	57.61	789.8	789.8	828.3
27/04/08	16	38.425	55.29	-1	-1	-1	50.29	-1	50.29	21.45	55.29	7.95	34.58	55.29	439.6	439.6	439.6
27/04/08	17	50.61	53.6	-1	-1	-1	48.6	-1	55.01	23.64	56.5	16.18	35.00	53.60	867.2	867.2	789.0
27/04/08	18	49.6125	50	-1	-1	-1	46	-1	50.1	24.715	53	13.63	35.00	50.00	681.5	681.5	606.8
27/04/08	19	43.56	50	-1	-1	-1	46	-1	50	28.345	54	16.95	38.00	50.00	847.5	847.5	786.6
27/04/08	20	39.815	52.5	-1	-1	-1	50.5	-1	55.74	34.0675	55.74	27.15	41.00	52.50	1425.4	1425.4	1406.8
27/04/08	21	34.1775	54.2	34.12	48.78	-1	49.2	-1	56.89	-1	54.2	27.42	42.77	54.20	1486.2	1486.2	1486.5
27/04/08	22	29.14	68.89	34.225	57.5	-1	62	-1	56.97	-1	52.18	37.85	42.84	68.89	2607.5	2380.6	2455.1
27/04/08	23	24.885	64.75	34.605	55.04	-1	58.28	-1	56.75	-1	52	49.75	64.75	65.03	3221.3	3221.3	3126.9
27/04/08	24	26.7125	57.6	34.19	41.35	-1	52.6	-1	49.6	-1	50	56.38	57.60	57.78	3247.5	3247.5	3126.0

Table 4.8 – DB3 – results of R_{UL}, R_{LL} and R_{ID} for 12/11/08.

Day	Hour	Day-Ahead		ID1		ID2		ID3		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	IDS_{NWP} (MW)	IDP_{SP} (€/MWh)	(MW)	BPD_{SP} (€/MWh)	BPU_{SP} (€/MWh)	(€)	(€)	(€)
12/11/08	1	48.9275	62.74	-1	-1	35.68	59.6	-1	-1	-1	-1	94.78	62.74	62.74	5946.5	5946.5	5988.1
12/11/08	2	48.4125	60	-1	-1	34.6375	59.5	-1	-1	-1	-1	94.79	60.00	62.51	5687.4	5687.4	5694.3
12/11/08	3	45.3275	57.11	-1	-1	33.9825	54.25	-1	-1	-1	-1	94.71	28.38	57.11	5408.9	3990.1	3696.6
12/11/08	4	40.515	56.72	-1	-1	36.2175	53.88	-1	-1	-1	-1	91.24	39.62	56.72	5175.1	4307.7	4246.5
12/11/08	5	38.315	56.72	-1	-1	-1	49.72	42.875	49.52	-1	-1	91.41	26.52	56.72	5184.8	3581.3	3686.2
12/11/08	6	31.0975	57.85	-1	-1	-1	50.85	42.6825	49.17	-1	-1	94.75	20.01	57.85	5481.3	3072.7	3410.5
12/11/08	7	24.285	61.67	-1	-1	-1	60	39.2275	55.5	-1	-1	94.72	61.67	61.67	5841.4	5841.4	5749.2
12/11/08	8	28.6825	74	-1	-1	-1	63.64	36.21	62.9	-1	-1	92.6	56.50	74.00	6852.4	5733.8	5782.0
12/11/08	9	29.79	78.22	-1	-1	-1	70.4	30.84	66.49	-1	-1	67.34	59.28	78.22	5267.3	4556.1	4563.7
12/11/08	10	32.665	79.46	-1	-1	-1	77.46	29.07	67.54	-1	-1	49.74	59.94	79.46	3952.3	3619.0	3591.7
12/11/08	11	32.4675	78	-1	-1	-1	77.7	47.8225	67.08	-1	-1	51.99	59.59	78.00	4055.2	3695.8	3810.8
12/11/08	12	10.8	77.79	-1	-1	-1	75.07	-1	70.01	53.9675	66.58	57.38	58.98	77.79	4463.6	3587.4	3915.5
12/11/08	13	8.265	74.2	-1	-1	-1	66.78	-1	63.07	45.645	63.07	57.93	60.35	74.20	4298.4	3610.5	3712.2
12/11/08	14	14.2875	71.7	-1	-1	-1	64.53	-1	59.51	41.7075	63.52	52.72	54.55	71.70	3780.0	3120.9	3366.9
12/11/08	15	10.175	64.6	-1	-1	-1	64.49	-1	61.17	32.2275	58.14	33.43	56.23	64.60	2159.6	1964.9	2007.1
12/11/08	16	10.83	64.6	-1	-1	-1	64.6	-1	61.17	20.405	64.52	38.47	53.32	64.60	2485.2	2173.4	2280.6
12/11/08	17	16.03	66.07	-1	-1	-1	65.87	-1	63.52	12.9275	65.02	40.87	54.72	66.07	2700.3	2418.3	2386.4
12/11/08	18	15.1275	74.3	-1	-1	-1	66.87	-1	63.16	11.94	65.44	35.36	54.72	74.30	2627.2	2231.1	2196.9
12/11/08	19	15.225	83.23	-1	-1	-1	80.32	-1	79.8	13.6725	83.23	29.47	57.42	83.23	2452.8	2085.1	2045.1
12/11/08	20	17.9475	87.84	-1	-1	-1	84.77	-1	86.04	14.1	87.84	34.4	56.25	87.84	3021.7	2502.0	2380.4
12/11/08	21	13.7075	85.01	5.915	76.51	-1	82.9	-1	83.21	-1	85.01	34.04	57.99	85.01	2893.7	2344.4	2200.0
12/11/08	22	11.2	80	5.9075	64	-1	66.4	-1	67	-1	65.58	45.18	59.33	80.00	3614.4	2912.0	2887.3
12/11/08	23	18.9725	71.9	6.725	61.12	-1	61.9	-1	64.7	-1	64.52	68.99	58.04	71.90	4960.4	4267.1	4229.4
12/11/08	24	29.8225	66.68	8.335	60.01	-1	63.52	-1	63.52	-1	63.52	87.09	54.44	66.68	5807.2	5106.2	4986.5

In both Tables, 4.7 and 4.8, one can witness an interesting phenomenon. There are some hours, for example hours 23 and 24 of 27/04/2008 and hours 1 and 2 of 12/11/2008, in which the R_{LL} equals the R_{UL}. However, this was only possible since the price of the BPD_{SP} and the DAP_{SP} were also equal in those hours. As a matter of fact, this can be proved mathematically: considering the general expression for the calculation of the R_{LL} (4.2), and replacing BP for BPD, because in all those hours the AG exceeded the DAS, we reach (4.4).

$$R_{LL} = (DAS \times DAP) + \{(AG - DAS) \times BPD\} \tag{4.4}$$

Given that in all those periods the BPD equalled the DAP, it is possible to rewrite (4.4) as (4.5).

$$R_{LL} = (DAS \times DAP) + \{(AG - DAS) \times DAP\} \tag{4.5}$$

Rearranging the terms, (4.5) can be written as (4.6).

$$R_{LL} = (DAS \times DAP) + (AG \times DAP) - (DAS \times DAP) \tag{4.6}$$

Finally,

$$R_{LL} = (AG \times DAP) = R_{UL} \ . \tag{4.7}$$

Moreover it is also clear in those same hours that the R_{ID} exceeds the other two revenues. This occurs due to the equality between the BPD_{SP} and the DAP_{SP} as well as the IDP_{SP} being lower than those two values. Taking as an example hour 1 of Table 4.8, the wind producer executed a first prediction in the day-ahead market of 48.9 MW and was paid for that prediction at DAP_{SP}, 62.74 €/MWh. In the ID session, he corrected that initial forecast to 35.68 MW and bought the difference between the IDS and the DAS, 13.22 MW, at 59.6 €/MWh, meaning that he made a financial profit of 13.22 MW x (62.74-59.6) €/MWh. However, this correction was wrongly performed, since the AG was 94.78 MW. Consequently, the wind producer exposed a difference between AG and IDS, 59.1 MW, bigger than the one between AG and DAS, 45.9 MW, to the system operator's BP. Still, he was fortunate and was paid that difference (between the AG and the IDS) at day-ahead market price, since the BPD_{SP} equalled the DAP_{SP} in this particular hour. All in all, the wind producer was not as penalised as he would have been if the BPD_{SP} was lower than the DAP_{SP}, like what happens in the majority of the occasions and he even made a profit due to the difference between the DAP_{SP} and the IDP_{SP}.

Figure 4.13 shows the yearly revenues of the wind producer, YR_{UL}, YR_{LL} and YR_{ID}, calculated with the contents of DB3.

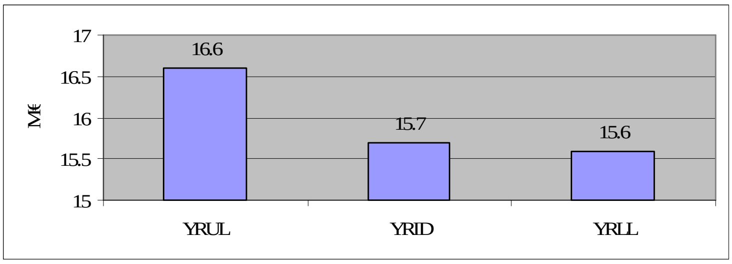

Figure 4.13 – YR_{UL}, YR_{ID} and YR_{LL} obtained with the features of DB3.

One relevant conclusion to retain at this point is that the difference between the different scenarios is much lower than in the previous cases. This is due mainly to two factors: the availability of ID prices for correcting the schedules and the lower difference between the day-ahead price, the balancing price downwards and the balancing price upwards of the Spanish area (DAP_{SP}, BPD_{SP} and BPU_{SP}).

4.2.4 Results using ARMA prediction models (DB4, DB5 and DB6)

In this section it will be presented the results of the data bases that make use of ARMA models to operate the adjustments in ID sessions. The methodology applied to match the ARMA forecasts with the intraday sessions is explained in Appendix C.

4.2.4.1 DB4

This data base is similar to DB1, with the sole difference of replacing the intraday schedule based on NWP methods (IDS_{NWP}) by the intraday schedule based on ARMA models (IDS_{ARMA}). In Tables 4.9 and 4.10 are shown the results of R_{UL}, R_{LL} and R_{ID} for two particular days.

Table 4.9 – DB4 – results of R_{UL}, R_{LL} and R_{ID} for 27/04/08.

Day	Hour	Day-Ahead		ID1		ID2		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
27/04/08	1	5.6475	56.69	-1	-1	15.904	47.92	-1	-1	16.94	43.7	69.7	960.3	813.6	856.9
27/04/08	2	5.31	54.53	-1	-1	17.171	46	-1	-1	15.94	44.6	64.5	869.2	763.7	755.8
27/04/08	3	5.3625	56.69	-1	-1	18.314	44.46	-1	-1	11.64	30.6	82.7	659.9	496.1	327.9
27/04/08	4	6.0025	57.62	-1	-1	19.396	49.71	-1	-1	14.01	34.3	81.0	807.3	620.5	575.4
27/04/08	5	4.7875	54.61	-1	-1	20.414	49.81	-1	-1	13.65	6.7	102.5	745.4	320.8	346.5
27/04/08	6	4.2075	54.6	-1	-1	21.373	49.81	-1	-1	13.89	48.5	60.7	758.4	699.3	630.5
27/04/08	7	0.405	54.5	-1	-1	22.275	51	-1	-1	7.67	36.6	72.4	418.0	288.0	80.0
27/04/08	8	0.7	53.77	-1	-1	23.124	44.38	-1	-1	3.24	13.7	93.9	174.2	72.4	-834.3
27/04/08	9	2.5825	53.68	-1	-1	23.923	44.71	-1	-1	23.73	30.7	76.7	1273.8	787.9	1078.0
27/04/08	10	2.4325	55	-1	-1	24.676	52.5	-1	-1	13.39	29.5	80.5	736.5	457.0	393.0
27/04/08	11	3.0975	56.75	-1	-1	25.384	51.75	-1	-1	0.03	64.8	48.7	1.7	26.4	94.4
27/04/08	12	3.5925	57.48	-1	-1	-1	54	4.405	-1	0.71	62.6	52.3	40.8	55.7	55.7
27/04/08	13	7.16	58.04	-1	-1	-1	53.04	6.39	-1	2.05	49.5	66.6	119.0	75.2	75.2
27/04/08	14	13.9975	58.87	-1	-1	-1	55.37	8.141	-1	6.75	43.8	73.9	397.4	288.4	288.4
27/04/08	15	23.305	57.61	-1	-1	-1	52.61	9.806	-1	13.71	46.3	68.9	789.8	681.5	681.5
27/04/08	16	38.425	55.29	-1	-1	-1	50.29	11.371	-1	7.95	35.2	75.4	439.6	-173.3	-173.3
27/04/08	17	50.61	54.43	-1	-1	-1	48.6	12.845	-1	16.18	45.8	63.0	880.7	585.6	585.6
27/04/08	18	49.6125	53.31	-1	-1	-1	46	14.232	-1	13.63	35.6	71.0	726.6	90.1	90.1
27/04/08	19	43.56	53.69	-1	-1	-1	46	15.539	-1	16.95	47.7	59.7	910.0	750.1	750.1
27/04/08	20	39.815	54.53	-1	-1	-1	50.5	16.769	-1	27.15	35.0	74.1	1480.5	1232.6	1232.6
27/04/08	21	34.1775	54.69	19.605	-1	-1	49.2	-1	-1	27.42	43.7	65.7	1499.6	1425.2	1425.2
27/04/08	22	29.14	68.89	20.307	-1	-1	62	-1	-1	37.85	47.5	90.3	2607.5	2421.2	2421.2
27/04/08	23	24.885	64.75	21.304	-1	-1	58.28	-1	-1	49.75	37.1	92.4	3221.3	2533.8	2533.8
27/04/08	24	26.7125	57.6	22.198	-1	-1	52.6	-1	-1	56.38	45.3	69.9	3247.5	2882.6	2882.6

Table 4.10 – DB4 – results of R_{UL}, R_{LL} and R_{ID} for 14/11/08.

Day	Hour	Day-Ahead		ID1		ID2		ID5		AG	BP		R_{UL}	R_{LL}	R_{ID}
		DAS (MW)	DAP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	IDS_{ARMA} (MW)	IDP_{PT} (€/MWh)	(MW)	BPD_{PT} (€/MWh)	BPU_{PT} (€/MWh)	(€)	(€)	(€)
14/11/08	1	18.2175	81.33	-1	-1	1.675	64.94	-1	-1	0.28	39.7	123.0	22.8	-724.7	235.8
14/11/08	2	18.2175	79.4	-1	-1	3.388	61	-1	-1	1.71	22.3	136.5	135.8	-806.8	312.8
14/11/08	3	20.2375	76.02	-1	-1	5.028	43.88	-1	-1	2	43.4	108.7	152.0	-444.0	541.9
14/11/08	4	24.275	71	-1	-1	6.57	-1	-1	-1	0.48	50.1	91.9	34.1	-463.2	-463.2
14/11/08	5	29.1075	65.89	-1	-1	8.016	-1	-1	-1	1.82	52.9	78.8	119.9	-232.4	-232.4
14/11/08	6	32.97	65.87	-1	-1	9.373	-1	-1	-1	8.95	47.9	84.4	589.5	144.4	144.4
14/11/08	7	33.645	71	-1	-1	10.647	-1	-1	-1	13.55	44.8	97.2	962.1	435.6	435.6
14/11/08	8	30.3825	80.88	-1	-1	11.842	80.88	-1	-1	26.85	47.1	114.6	2171.6	2052.5	1664.7
14/11/08	9	28.035	79.8	-1	-1	12.964	75	-1	-1	37.85	41.0	118.5	3020.4	2639.6	2127.2
14/11/08	10	25.4875	81.39	-1	-1	14.016	74.51	-1	-1	29.46	50.7	112.1	2397.7	2275.8	2002.7
14/11/08	11	19.93	82.43	-1	-1	15.003	-1	-1	-1	17.11	66.9	97.9	1410.4	1366.8	1366.8
14/11/08	12	14.1275	83.15	-1	-1	-1	-1	30.318	69.45	7.01	67.0	99.3	582.9	467.9	-15.4
14/11/08	13	8.9775	85.12	-1	-1	-1	-1	30.564	70.84	7.04	71.7	98.5	599.2	573.3	-23.8
14/11/08	14	5.2775	84.27	-1	-1	-1	-1	30.553	67.49	10.91	64.7	103.8	919.4	809.2	111.6
14/11/08	15	2.7525	83.23	-1	-1	-1	-1	30.522	62.77	6.11	73.2	93.3	508.5	474.9	-305.5
14/11/08	16	1.275	85.12	-1	-1	-1	-1	30.492	65	3.81	73.3	96.9	324.3	294.3	-577.9
14/11/08	17	0.3375	85.12	-1	-1	-1	-1	30.463	67.5	0	77.7	92.6	0.0	-2.5	-758.7
14/11/08	18	2.0225	84.27	-1	-1	-1	-1	30.436	71.95	0	74.9	93.6	0.0	-18.9	-634.0
14/11/08	19	7.0825	84.2	-1	-1	-1	85.61	30.411	-1	1.07	76.8	91.6	90.1	45.6	45.6
14/11/08	20	20.9725	88.34	-1	-1	-1	91.95	30.388	-1	10.47	93.0	83.7	924.9	973.7	973.7
14/11/08	21	44.0175	84.51	0.488	-1	-1	83.26	-1	-1	53.11	82.8	86.2	4488.3	4472.8	4472.8
14/11/08	22	59.77	83.12	2.2	78	-1	-1	-1	71.76	60.42	74.6	91.6	5022.1	5016.6	4820.8
14/11/08	23	66.3875	81.69	3.908	74.28	-1	-1	-1	69.03	55.28	65.0	98.3	4515.8	4331.3	4121.4
14/11/08	24	67.975	81.18	5.518	64.6	-1	-1	-1	61.01	55.68	52.3	110.1	4520.1	4164.5	4107.0

From the inspection of Tables 4.9, 4.10, we can conclude that, generally, the R_{UL} exceeds both the R_{LL} and the R_{ID}, as it was expected. The relation between the R_{LL} and the R_{ID} depends directly from the accuracy of the IDS_{ARMA}. For instance, in the first three hours of 14/11/2008, it is evident that the wind producer benefited from the participation in the ID sessions. Indeed, in the first hour of 14/11/2008, the R_{ID} exceeded the R_{LL} in 960.5 €. In hour 2, that difference was raised to 1119.6 €, in favour of the R_{ID}. In the third hour, the R_{ID} again surpassed the R_{LL} by 985.9 €. These three cases are elucidative of the financial advantage that the wind producer may get from a good correction in the ID market.

Conversely, there are also many examples of situations in which the R_{LL} surpassed the R_{ID} (hour 8 of Table 4.9 or hour 12 of Table 4.10), mainly due to inaccuracy in the generation adjustments operated in the ID sessions.

Figures 4.14 and 4.15 show the relation between the day-ahead schedule (DAS), the intraday schedule based on ARMA models (IDS_{ARMA}) and the AG in the same two days analysed in Tables 4.9 and 4.10.

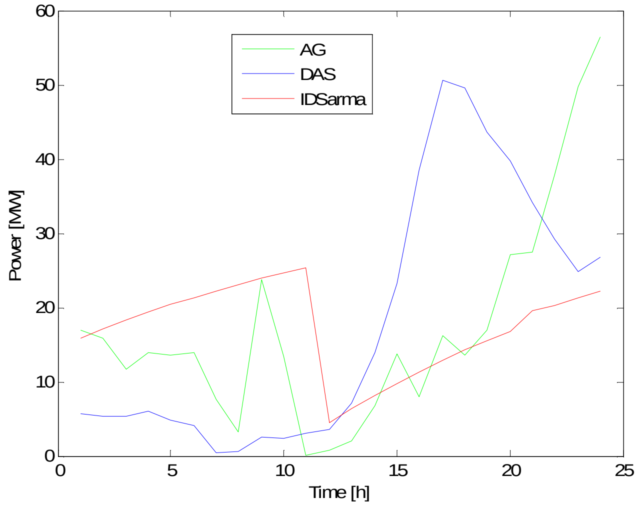

Figure 4.14 – DAS, IDS_{ARMA} and AG in 27/04/2008.

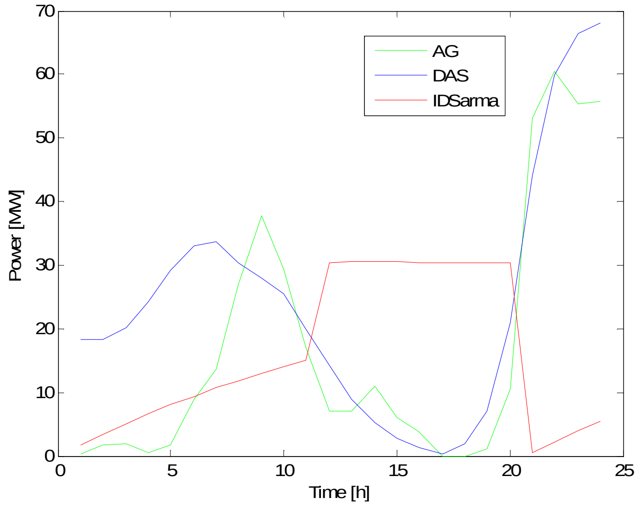

Figure 4.15 – DAS, IDS_{ARMA} and AG in 14/11/2008.

Figure 4.16 shows the yearly revenues of the wind producer in the upper limit, lower limit and intraday situations (YR_{UL}, YR_{LL} and YR_{ID}) calculated with the contents of DB4.

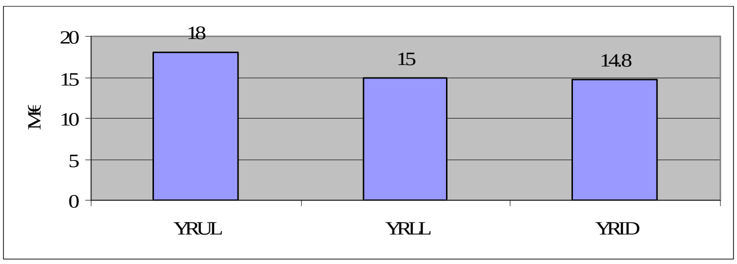

Figure 4.16 – YR_{UL}, YR_{ID} and YR_{LL} obtained with the features of DB4.

4.2.4.2 DB5

Figure 4.17 shows the yearly revenues of the wind producer, YR_{UL}, YR_{LL} and YR_{ID}, calculated with the contents of DB5.

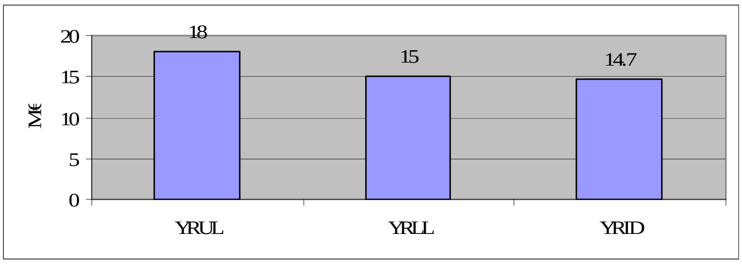

Figure 4.17 – YR_{UL}, YR_{ID} and YR_{LL} obtained with the features of DB5.

4.2.4.3 DB6

Figure 4.18 shows the yearly revenues of the wind producer, YR_{UL}, YR_{LL} and YR_{ID}, calculated with the contents of DB6.

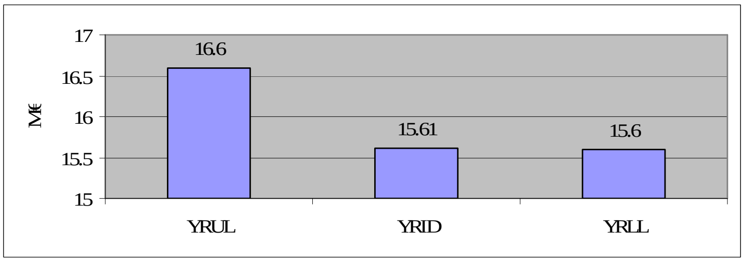

Figure 4.18 – YR_{UL}, YR_{ID} and YR_{LL} obtained with the features of DB6.

Table 4.11 summarizes not only the revenues of the wind producer obtained with the contents of the six data bases, but also the average price, AP, at which the energy generated by the wind farm was valued.

Table 4.11 – Summary of the yearly revenues of the wind producer and average price at which the energy he sold was valued, in each situation.

DB	YR_{UL} (M€)	AP_{UL} (€/MWh)	YR_{LL} (M€)	AP_{LL} (€/MWh)	YR_{ID} (M€)	AP_{ID} (€/MWh)
DB1	18	67.95	15	56.63	15.1	57
DB2	18	67.95	15	56.63	15.2	57.38
DB3	16.6	62.67	15.6	58.89	15.7	59.27
DB4	18	67.95	15	56.63	14.8	55.87
DB5	18	67.95	15	56.63	14.7	55.49
DB6	16.6	62.67	15.6	58.89	15.61	58.93

Note that the YR_{UL} and YR_{LL} are similar in DB1, DB2, DB4 and DB5 because the features that involve the determination of those two parameters are common to all these four DB. The same reasoning is applied to DB3 and DB6.

Moreover, comparing the average day-ahead market price of the Portuguese area in 2008, 69.975 €/MWh, with the average price at which the energy generated by the wind farm was valued in the upper limit situation (energy valued at day-ahead market price) in Portugal, 67.95 €/MWh, we conclude that there was a higher focus of the wind farm generation in off-peak hours (lower prices) than in peak hours (higher prices).

4.2.5 Consequences of forecast accuracy improvement

Given the results of the yearly revenues of the wind producer in all six data bases, it is evident that in each of them the difference between the YR_{ID} and the YR_{LL} was not as accentuated as it would be expected. Indeed, in DB4 and DB5 the YR_{ID} was even lower than the YR_{LL}. One of the aspects, and perhaps the most significant, that contributed to this phenomenon was the inaccuracy of the adjustments effectuated in the ID sessions.

Consequently, it was carried out a set of simulations to evaluate the impact on the YR_{ID} of an improvement of the corrections operated in the ID sessions. This improvement was accomplished by adding to the intraday schedule based on NWP methods (IDS_{NWP}) in each hour, 25%, 50% or 75% of the initial difference between the AG and the IDS_{NWP}. This procedure is mathematically detailed in expressions (4.8), (4.9), (4.10) and (4.11).

$$diff = AG - IDS_{NWP} \,. \tag{4.8}$$

$$IDS_{25} = IDS_{NWP} + (0.25 \times diff) \,. \tag{4.9}$$

$$IDS_{50} = IDS_{NWP} + (0.5 \times diff) \,. \tag{4.10}$$

$$IDS_{75} = IDS_{NWP} + (0.75 \times diff) \,. \tag{4.11}$$

The results of this improvement are graphically demonstrated in Figures 4.19 and 4.20.

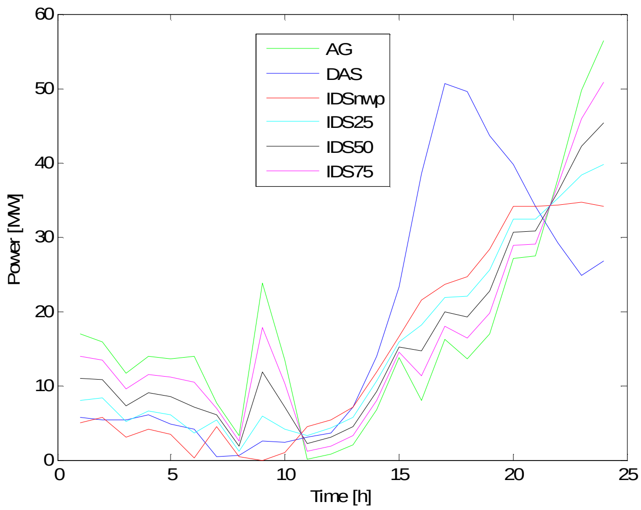

Figure 4.19 – DAS, IDS_{NWP}, IDS_{25}, IDS_{50} IDS_{75} and AG in 27/04/2008.

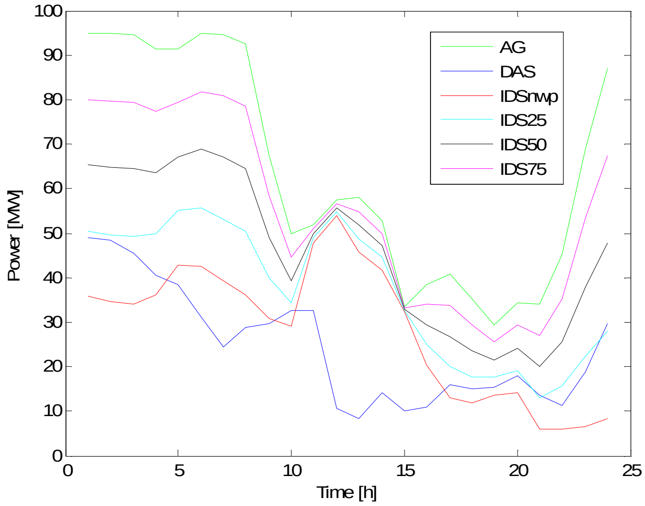

Figure 4.20 – DAS, IDS_{NWP}, IDS_{25}, IDS_{50} IDS_{75} and AG in 12/11/2008.

One may witness in Figures 4.19 and 4.20 that the IDS_{25}, IDS_{50} and IDS_{75} minimize the initial unbalance between the AG and the DAS, improving also the accuracy of the IDS_{NWP} used in the first three DB.

Let us call the yearly revenues that derive from these adjustments in the IDS, YR_{25} YR_{50} and YR_{75}.

Figures 4.21, 4.22 and 4.23 illustrate the YR_{25}, YR_{50}, YR_{75} and YR_{100}[34] for DB1, DB2 and DB3. In both Figures, it was also included the YR_{UL}, the YR_{LL} and the YR_{ID} that derive from Figures 4.9, 4.12 and 4.13, respectively.

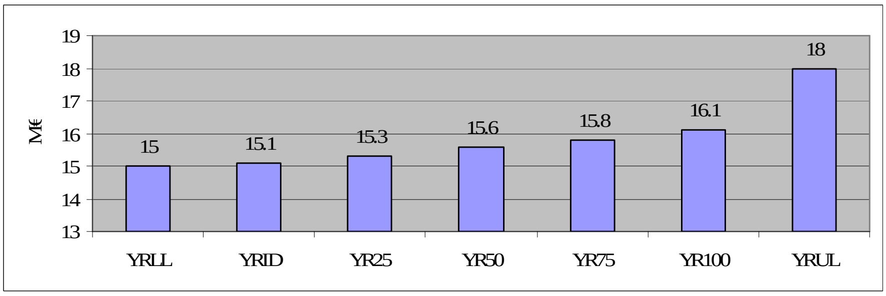

Figure 4.21 – Result of the IDS adjustment in DB1.

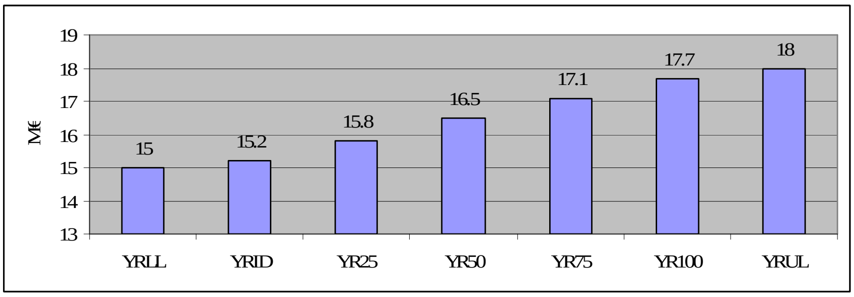

Figure 4.22 – Result of the IDS adjustment in DB2.

[34] In this hypothetical scenario, there would be a match between the intraday schedule operated by the wind producer and the actual generation of the wind farm.

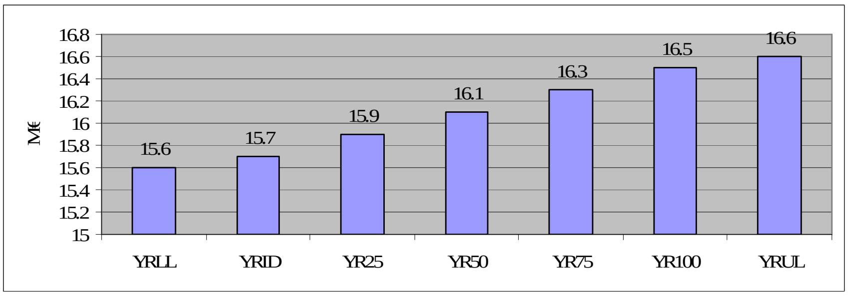

Figure 4.23 – Results of the IDS adjustment in DB3.

Note that in all these three Figures, 4.21, 4.22 and 4.23, it was included a yearly revenue that assumed the wind producer corrected perfectly the forecast in the intraday markets (YR_{100}). In other words, it was presupposed that there was a match between the intraday schedule and the actual generation of the wind farm. It is curious to observe that even with this perfect correspondence the yearly revenue of the wind producer would not be identical to the one in the upper limit situation. This occurs because in the upper limit situation, all the energy generated by the wind farm is valued at day-ahead market price. On the other hand, in the perfect correction situation, one part of the energy is valued at day-ahead market price (DAP) and the other at intraday price (IDP). They would only be equal in case the IDP was similar to the DAP. This allows us to draw one conclusion, which is that the day-ahead market price was, on average, higher than the intraday price.

These adjustments in the IDS were only performed for DB1, DB2 and DB3 since the results for the remaining data bases would be very similar. Furthermore, the results expressed in Figures 4.21, 4.22 and 4.23 provide evidence that an improvement in the accuracy of the IDS has a high direct impact on the yearly revenue of the wind producer. It can also be observed that the gains arising from better accuracy are higher in DB2 and DB3, the ones where there are no hours without ID prices. This shows the importance of intraday market liquidity for the financial results of wind generation in a market environment. Finally, it is also important to point that very low balancing prices downwards (BPD) and very high balancing prices upwards (BPU) have strong negative impacts on the wind producer performance.

4.2.6 Discussion of results

In this part of the work it will be analysed the results obtained in section 4.2, as well as identifying possible measures that would mitigate some drawbacks related to the participation of a wind producer in the power market, namely market design issues and operation strategies.

4.2.6.1 Comparison of market results assessment and actual revenue in 2008

An accurate analysis of the wind farm performance in a market environment cannot be done without knowing the current environment of wind generation remuneration in Portugal, the feed-in tariff regime. Effectively, the actual revenue of the wind farm studied in this thesis was, approximately, 24.2 M€ in 2008 [ERSE] a value which exceeds largely all scenarios revenues, determined in each of the six data bases (Table 4.11). Assuming the energy generated by the wind farm was all valued at day-ahead market price, the wind producer would "only" collect 18 M€, using the DAP of the Portuguese area. This value, which concerns the upper limit situation in DB1, DB2, DB4 and DB5, is surpassed by the effective revenue of the wind farm in over 6 M€. Regarding the revenues in both the lower limit and the ID situations, the difference towards the effective revenue raises to values between 8 M€ (in DB3 and DB6) and 9 M€ (in DB1, DB2, DB4 and DB5).

Overall, the main conclusion that one can take from the above reasoning is that in all projected scenarios, based on 2008 market prices, the yearly revenue of the wind producer by the time he enters in the power market[35] would be significantly lower than the one he receives from the application of the feed-in tariff. Even in the putative situation of matching the intraday schedule with the actual generation of the wind farm, the correspondent yearly revenue, YR_{100}, would be surpassed in 8 M€ in DB1, 6.5 M€ in DB2 and 7.7 M€ in DB3[36] by the effective revenue in 2008.

Facing these reductions in the revenues, one could be induced to affirm that the wind producer will start losing money as soon as he starts participating in the power market. However, that reasoning is a too simple one. In fact, it is likely that the business case that has supported the project included a recovering of the investment capital (or at least a large part of it) by the time the wind farm ceases its tariff regime. That way, the operation in a market environment must “only” allow recovering operation costs (low compared with other technologies) and the eventual residual part of investment costs, which makes that operation likely to be profitable. However, one must recognize that 2008 market prices were very favourable for generators compared to other years, namely 2009[37], and that the differences between tariff and market regimes may be higher if the trend in electricity prices evolution occurred in 2009 was to happen when the tariff regime comes to an end.

4.2.6.2 Assessing the impact of market price volatility

Wind producers, when entering the power market, will be confronted with several circumstances with which they are not used to deal with. One of the most important is that their yearly revenue will be function of highly unpredictable variables, namely day-ahead market price. This creates a total disruption towards the remuneration method that is reaching its end: the feed-in tariff. Indeed, with the actual regime, wind producers know, in advance, the price at which the energy they will sell is going to be valued, which will no longer be the case in a market environment and will imply a higher volatility of annual revenues perceived by them.

In order to assess how volatile the revenues of wind producers can be to day-ahead price, it was estimated what would be the yearly revenue of the wind producer studied in this work, in the upper limit situation, in 2007 and 2009, based on the actual generation of the wind farm of 2008. This estimation was executed according to (4.12) and (4.13),

$$YR_{UL\,2007} = \frac{YR_{UL\,2008}}{DAP_{2008}} \times DAP_{2007} \tag{4.12}$$

$$YR_{UL\,2009} = \frac{YR_{UL\,2008}}{DAP_{2008}} \times DAP_{2009} \tag{4.13}$$

where:

[35] This revenue will have other item related to the selling of green certificates by the wind producer, which was not studied in this thesis.
[36] See Figures 4.21, 4.22 and 4.23.
[37] See Table 4.12.

YR_{UL2007}, YR_{UL2008} and YR_{UL2009} are the yearly revenues of the wind producer in the UL situation in 2007, 2008 and 2009, respectively;

DAP_{2007}, DAP_{2008} and DAP_{2009} are the average day-ahead market prices of 2007, 2008 and 2009, respectively.

Furthermore, it was also determined the average price at which the wind producer would sell his energy, in the UL situation, in 2007 and 2009, also based on the actual generation of the wind farm in 2008. These results are expressed in Table 4.12.

Table 4.12 – Average day-ahead market price of the Portuguese area, yearly revenue of the wind producer in the UL situation and average price of the energy sold by the wind producer in the UL situation in 2007[38], 2008 and 2009[39].

Year	Average DAP (€/MWh)	YR_{UL} (M€)	Average Price (YR_{UL}) (€/MWh)
2007	52.18	13.4	50.58
2008	69.98	18	67.94
2009	39.11	10.1	38.12

As one may witness in Table 4.12, since the implementation of the day-ahead market in Portugal in July 2007, until 30 September 2009, the day-ahead market price, on average, suffered considerable fluctuations. These fluctuations have a direct impact on the average price at which the wind producer sells his energy and, subsequently, can change dramatically the financial income of the wind producer if exclusively dependent on the day-ahead market price. The differences between the YR_{UL2008} and the YR_{UL2007} (4.6 M€) and between the YR_{UL2008} and the YR_{UL2009} (almost 8 M€) are an unmistakable proof of that.

Besides, it is important to emphasize that this analysis was only executed for the upper limit situation, which only had the influence of the day-ahead market price. However, in a real market environment, the wind producer, besides the DAP, will have to deal, at least, with two more variables that will turn his financial income even more unpredictable: intraday prices (IDP) and balancing prices (BP).

4.2.6.3 The impact of market design features

In this section the impact of balancing prices on the revenue of the wind producer will be discussed. Furthermore, there is also allusion to the importance of the liquidity of the intraday prices and to the relation between ID price liquidity and forecast reliability.

Balancing costs

To start this section, let us focus on the yearly revenue of the wind producer in the upper limit situation (YR_{UL}) and in the lower limit case (YR_{LL}), for two specific scenarios corresponding to Portuguese and Spanish prices respectively. To this purpose one may take into consideration the relevant results of DB1 and DB3 in Table 4.11 whose underlying data refers to Portugal (DB1) and Spain (DB3). It is clear that the YR_{UL} of DB1 surpasses the

[38] Day-ahead market prices since 1 July 2007.
[39] Day-ahead market prices until 30 September 2009.

one of DB3, what denotes that the DAP_{PT} exceeds, on average, the DAP_{SP}[40]. Moreover, it is also highly relevant to point that the difference between the YR_{UL} and the YR_{LL} calculated with the Spanish prices is much smaller than the one determined with the Portuguese ones. Actually, that difference is reduced from 3 M€ in DB1 to 1 M€ in DB3. This signifies that the Spanish balancing prices are more in line with the day-ahead prices and that the Portuguese ones penalise more severely the wind producer. Table 4.13 shows the spread of the average difference between the day-ahead price (DAP) and the balancing price downwards (BPD) and the balancing price upwards (BPU) and the DAP, in Portugal and Spain.

Table 4.13 – Spread of the average differences [DAP - BPD] and [BPU - DAP] in Portugal and Spain (2008).

	AVG[DAP-BPD] (€/MWh)	AVG[BPU-DAP] (€/MWh)
Portugal	21.3	20.8
Spain	8.03	4.05

The inspection of Table 4.13 allows drawing important conclusions regarding the impact of balancing prices in the revenue of the wind producer. The first one is that, in both countries, the day-ahead price (DAP) exceeds, on average, the BPD. On the opposite, it is also plain in Table 4.13 that the day-ahead price is, on average, lower than the BPU. These two aspects penalise the wind producer for inaccurate forecasts, as it was pointed in chapter three. However, as one can witness in Table 4.13, that penalisation is much more severe in Portugal, where average balancing prices deviate from average market prices by approximately 30%, than in Spain, leading to the dissimilarity in the difference between the YR_{UL} and the YR_{LL} in DB1, 3 M€, and in DB3, 1 M€. To sum up, the participation of wind producers in the market require that the balancing prices in Portugal are less penalising than they were in 2008, i.e. that the spread to the day-ahead market becomes lower and converges with the Spanish case, which could be achieved by granting the Portuguese agents the access to the Spanish balancing market (and vice-versa). In case this occurs, the wind producer will be given the opportunity of shorting the difference between the yearly revenue in the lower and upper limit situations. On the whole, he would see the energy he sells converge to a price closer to DAP.

The announced cooperation between REN and REE towards a harmonization of Portuguese and Spanish balancing markets is likely to pave the way for a better level playing field for renewables in Portugal.

Liquidity of Intraday market prices

The inclusion of wind producers in the power market requires liquid intraday markets. One of the reasons why the intraday scenarios in the Portuguese case did not perform as well as in the Spanish case was the lack of intraday prices in Portugal in many hours, which means that there were no counterparties available to trade. Indeed, in DB1 only 37% of the 8784 hourly periods had intraday prices available. This is a strong drawback for any decision towards a market-based strategy.

However, the good news is that the entry of new players in the market (wind producers), who strongly need to adjust their positions in the intraday sessions, is likely to foster liquidity. Traditional participants will pay more

[40] Since the AG of the wind farm is common to all data bases.

attention to the intraday market sessions as they know that the probability of finding counterparts interested in trading is much higher than actually and the liquidity and traded volumes will rise.

Intraday market model

It is by all means undeniable that the accuracy of the adjustments performed in the intraday sessions has a direct impact in the financial income of a wind producer. However, having a good prediction for a particular intraday session that, in the end, had no price, i.e. no counterparty to negotiate, is worthless. Consequently, the wind producer has to play with these two variables in order to find the best possible match between forecast (intraday schedule) and intraday price liquidity. Table 4.14 alludes for this fact.

Table 4.14 – Relation between forecast reliability and ID price liquidity.

	Long Term	Short Term
Forecast Reliability	-	+
ID price Liquidity	+	-

Table 4.14 shows that forecast reliability and ID price liquidity have opposed characteristics: if the intraday corrections are performed far in advance, there is more liquidity in the ID prices but the forecast is not as reliable as it would be if it was made closer to real time; on the opposite, in case the prediction is executed to take advantage of all intraday sessions, the forecast ought to be reliable, but there is the risk of not having counterparties to negotiate due to lack of liquidity. A better or worse financial income for the wind producer will rely on the equilibrium of these conflicting aspects.

From the wind producer's perspective, though, a continuous intraday market would be the ideal solution to remove the problem of meeting generation forecast with the ID sessions. Like that, he would have a permanent platform to trade at any time, according to the predictions he would make for the generation of the wind farm in each hour. Consequently, the incompatibility shown in Table 4.14 would not be a dilemma anymore. This model is already applied e.g. by NordPool in the Nordic market.

4.2.6.4 Generation forecast

In this section it will be drawn conclusions regarding the relevance of the accuracy of the corrections performed by the wind producer in the intraday sessions. The forecasting models used in this work are also object of discussion.

Forecast accuracy

The simulations of section 4.2.5 had the utmost intention of proving that an improvement in the accuracy of the intraday schedules would have a direct impact in the yearly revenue of the wind producer in the intraday situation (YR_{ID}). The consequence of this impact would be an increase of the difference between the original YR_{ID} and the yearly revenue of the wind producer in the lower limit situation (YR_{LL}). However, looking at

Figure 4.21 one could be tempted to affirm that the impact of a forecast accuracy improvement was irrelevant, once the difference between the YR_{75}[41] and the YR_{LL} was less than 1 M€. That commentary would be reasonable if one did not take into consideration that the results illustrated in Figure 4.21 were obtained with the features of DB1, a data base including exclusively the intraday prices of the Portuguese area where, as one may remember, in 2008, there were over 63% of the hours that had no ID price. In Figure 4.22, though, the impact of the forecast accuracy improvement is much more emphasized, due to the existence of prices in all intraday sessions[42]. In this Figure, we can observe that the difference between the YR_{50} and the YR_{LL} is 1.5 M€, rising to over 2 M€ in case we compare the YR_{75} with the YR_{LL}. Of course, the difference between the yearly revenue in the upper limit situation and the yearly revenues with forecast accuracy improvement is successively reduced according to the quality of the improvement. The original YR_{ID} was almost 3 M€ less than the $YR_{UL,}$ whereas the difference between the YR_{UL} and the YR_{75} was less than 1 M€. Figure 4.23 shows the same phenomenon of Figure 4.22 but with the Spanish prices. The differences between the several yearly revenues with forecast improvement and the YR_{LL} are not as accentuated as the ones in Figure 4.22, because the difference between the yearly revenue of the wind producer in the upper and lower limits was by itself very short: 1 M€.

The analysis performed shows that an accurate generation forecast is a key issue for wind generation operating in a market environment.

Forecasting models

One of the main purposes for the creation of six data bases was varying the yearly revenue of the wind producer according to the intraday strategy (YR_{ID}) and compare it with the YR_{LL}. Theoretically, like it was detailed in section 4.2.2, the YR_{ID} would exceed the YR_{LL} since in the ID situation the wind producer could correct the day-ahead schedule in the intraday sessions[43], at more favourable prices than the balancing ones. Indeed, that was verified in DB1, DB2, DB3 and DB6, as one may witness in Table 4.11. Nevertheless, the difference between the YR_{ID} and the YR_{LL} in those data bases was not as accentuated as it was expected. Besides, in two DB, DB4 and DB5, the YR_{ID} was even lower than the YR_{LL}.

What contributed decisively for the occurrence of the above mentioned facts was the inaccuracy of the wind power forecasts utilized to perform the corrections in the ID markets, denominated IDS_{NWP} and IDS_{ARMA} depending on the method employed. This inaccuracy in the IDS_{NWP} and in the IDS_{ARMA} led to incorrect adjustments in the intraday sessions.

In reality, both NWP and ARMA models used in this study had some drawbacks. The IDS_{NWP} did not contain information related with persistence, what would improve the accuracy of the model. Regarding the IDS_{ARMA}, the training period employed was not the most appropriate. To forecast the generation of the wind farm for the full year of 2008, the period used to train the model should have been the actual generation of the wind unit in 2007. However, in the absence of that information, the training period utilized was the generation of the wind farm in December 2008, assuming that in the homologous period of 2007 the wind farm would have had an identical generation. This assumption denotes two inherent problems: one is that the generation of December

[41] YR_{75} was, after YR_{100}, the best forecast accuracy improvement implemented.
[42] This data base was created introducing the prices of the Spanish ID sessions in the correspondent ones in Portugal that had no price. The day-ahead market price and the balancing prices were both from Portugal.
[43] That correction corresponds to the difference between the intraday schedule and the day-ahead schedule.

2007 was surely not equal to the one of December 2008; the other is that the training period employed was too short. Choosing too short a period for model training leaves out some important information that would help the model's forecasting accuracy. The ideal training period to predict the generation of the wind farm for 2008 would pick up the important drivers and patterns for different times of the year 2007. These aspects did not allow extracting the maximum potentialities from the ARMA methodology.

Despite all these drawbacks, we foresee that the ideal strategy for wind producers when participating in the power market would be to use NWP methods to perform the forecast for the day-ahead market (DAS) and ARMA models to the intraday adjustments (IDS), or at least some of them, when the forecast is applied to nearer scheduling periods. On the basis of this deliberation is the fact NWP methods have a better behaviour for time horizons superior to 3 hours. On the opposite, ARMA models are likely to offer accurate forecasts within a time horizon of 30 minutes to 3 hours.

4.2.6.5 Strategy topics

Due to the fundamental differences that exist between the day-ahead and intraday market concepts, participants bidding strategies are also very diverse when approaching those two segments.

Effectively, the strategy of placing instrumental orders in the intraday sessions by wind producers, like it was assumed to be the case in the day-ahead operation does not seem to be a good strategy, for two fundamental reasons: the first one is that the participation in intraday sessions is not mandatory; the second one is that there is a limit for the valuation of the energy adjusted in the intraday market: the balancing prices. The foreseen value of those prices should be a limit for adjustment orders. For instance, imagine the wind producer is considering placing a selling order in one particular intraday session. One may be thinking that selling order would be placed at 0 €/MWh. Indeed, finding a counterparty to buy energy at 0 €/MWh is not the hardest of tasks. However, doing so, the wind producer was risking to actually sell the energy at zero price, in case there were no more trades in that same session, which is not impossible to occur. As a matter of fact, taking into account the lack of liquidity of the ID prices of Portugal in 2008, we could affirm that the probability of that happening was not negligible. Thus, we reach the conclusion that he should place that selling order at a price different than zero. But how different? Higher than the price he predicts for the system operator's balancing price downwards (BPD). In other words, if he places that ask at a price lower than BPD, he will be loosing money, because selling the same energy to the system operator would result in a higher revenue. All in all, he should place that selling order at a price he expects will be higher than BPD.

Let us now consider the case in which the wind producer wants to place a buying order in an intraday session. In this situation, the maximum price at which he is willing to buy that energy is the system operator's balancing price upwards (BPU). He should find a counterparty that is disposed to sell the energy he needs at a price he believes is lower than the BPU. It would not make sense buying that energy in the intraday market at a price higher than the BPU.

5 Conclusions

In this fifth chapter the main conclusions of the work are presented, alongside with suggestions of further studies regarding the introduction of renewable energies in the power market.

Final Remarks

Wind energy has suffered a breathtaking development over the past 10 years. To that rise contributed not only its green credentials, but also the support from government's policies. Furthermore, the new Renewable Energy Directive agreed in December 2008 set a new target of 20% of EU's final energy demand coming from renewables in 2020, which allows us to foresee that wind energy will continue its sustainable growth.

As outlined in the first chapter, wind energy is likely to benefit from market integration if investors in power plants are obliged to value a clean energy source which has no fuel costs. That integration has already occurred in reference countries in the wind power field like Spain or Denmark. Portugal will soon join these nations as we are reaching the end of feed-in tariff: Decree-Law number 225/2007 states that this remuneration method is applicable to the first 33 GWh/MW injected in the grid or to 15 years of installed power, which of the two occurs first.

In the second chapter it was portrayed the Portuguese electricity system, with particular focus on the entities that play key roles on it: generation, transmission, distribution, supply and operation of the regulated electricity market. In addition, it was represented the two segments of the Portuguese electricity market model: the liberalised and the regulated. In this second chapter we also gave preponderance to MIBEL and to its interconnected bipolar structure, where the day and intraday markets are operated by OMEL, under a market splitting model, and the organised derivatives market is under the responsibility of OMIP. The economic benefits of cross-border flow in an integrated market were identified and, subsequently, the main features of the two markets utilized to study the introduction of a particular wind farm in the power market were explained: the day-ahead market and the intraday market. We mentioned that the main purpose of the day-ahead market is to handle transactions for the following day through the presentation of selling and purchasing orders to the market operator, OMEL, who includes them in a matching procedure that comprises twenty-four consecutive programming hours. Regarding the intraday market, we concluded that this particular platform will be a vital tool for wind producers, as it is the last opportunity that market participants are offered to balance their schedules, i.e. it operates immediately before System Operator's balancing mechanisms.

In the third chapter it was described both the algorithms used to implement the market simulator and the model established of pricing wind energy in MIBEL's power market. Concerning the market simulator, the algorithm applied follows the market splitting mechanism, as it as it is the model used by Portugal and Spain to allocate interconnection capacity in the day-ahead timeframe. We concluded that this mechanism is characterized by the following procedure: firstly it is computed the equilibrium price (EP) with orders from both countries. Then, the resulting cross border flow origins two possible scenarios: if it does not exceed the net transfer capacity (NTC), the result is valid and both countries share the same equilibrium price; if it is higher than the NTC, the initial market with bids and asks from both countries is split into two separated markets, each one with its price. In relation to the inclusion of the wind producer in the power market, the main conclusion of this chapter was that the strategy performed should maximize the global economical results of the wind producer taking into account the overall operation cycle: day-ahead, intraday and system operation balancing. Consequently, it was decided that the optimal approach for the wind producer's perspective was correcting just once and in the last available intraday session for each hour the generation schedule made in the day-ahead market.

In chapter four we firstly concluded that the results of the market simulator carried out in this work were concordant with the ones of OMEL's public site. Additionally, six data bases were analysed in order to assess the performance of a wind farm in a market environment in several scenarios. For each of those scenarios, the yearly revenue of the wind producer was calculated for three distinct strategies: a first one, denominated the upper limit situation, in which the energy generated by the wind farm was all valued at day-ahead market price (DAP); a second one, named the lower limit situation, in which the wind producer did not correct the day-ahead schedule (DAS) in the intraday (ID) market sessions, exposing, consequently, the difference between the actual generation and the DAS to the system operator's balancing prices (BP); a third and last one, denominated the intraday situation, in which the wind producer adjusted the DAS just once for each hour and in the last available ID session. Furthermore, it was also studied the impact that a forecast accuracy improvement would have on the revenue of the wind producer.

One of the main conclusions that come up from this work is that in all projected scenarios, based on 2008 market prices, the yearly revenue of the wind producer by the time he enters in the power market would be significantly lower than the one he receives from the application of the feed-in tariff. Even though we know that the item related to the selling of green certificates was not taken into account, the differences between the several yearly revenues (18 M€ was the highest one in the upper limit situation) and the actual revenue of the wind producer in 2008, approximately 24.2 M€, were appreciable. Furthermore, it must be pointed out that 2008 market prices (average DAP in 2008 was 69.98 €/MWh) were very positive for generators compared to other years, namely 2007 (average DAP since 1 July 2007 was 52.18 €/MWh) and 2009 (average DAP until 30 September, 2009, was 39.11 €/MWh), and that the differences between tariff and market regimes can be significant if the tendency in electricity prices occurred in 2009 is to happen when the tariff regime ends.

This brings us to another pertinent remark of this thesis, which is the difficulty of wind producers, when attending the power market, to forecast the price at which they will sell their energy. This aspect is utterly different from the one wind producers are familiar with, because according to the actual regime, wind producers know, in advance, at what price will the energy they will sell going to be valued. However, with their inclusion in the electricity wholesale market, the yearly revenue of wind producers will be function of highly unpredictable variables: day-ahead prices, intraday prices and balancing prices.

Furthermore, it was also verified that the difference between the yearly revenue of the wind producer in the upper and lower limit situations calculated with the Spanish market prices, 1 M€, was smaller than the one determined with the prices of the Portuguese area, 3 M€. This feature allowed concluding that the Spanish balancing prices are more in line with the day-ahead prices and that the Portuguese ones penalise more severely the wind producer. However, if wind producers are to participate in the market, the balancing prices in Portugal need to be less penalising than they were in 2008, which can be accomplished by allowing a stronger integration between Portuguese and the Spanish balancing markets. This Iberian collaboration could offer renewable producers in Portugal a better playing field.

In addition, a crucial piece of the inclusion of wind producers in the power market is the intraday markets. As one could witness in chapter four, there was lack of liquidity in the intraday prices of the Portuguese area in

2008. This lack of liquidity can be a strong drawback for wind producers as they need the intraday platform to perform the corrections to the day-ahead schedule. Still, the good news is that the entry of new players in the market, namely wind producers, is likely to foster liquidity. Moreover, in order to have the best possible financial income the wind producer has to find the optimal equilibrium between intraday price liquidity and forecast reliability. Intraday corrections are likely to be more accurate closer to real time, but there is the risk of not having a counterparty to negotiate with. On the opposite, in case intraday corrections are executed far in advance, there is more liquidity in the intraday prices, but the forecast is not as accurate as it would be if it was made in the short term. To overtake this problem, wind producer would benefit from a continuous intraday platform, where he could trade whenever he liked, according to his generation predictions.

In relation to the generation forecasts, one of the main purposes for the creation of six data bases was varying the yearly revenue of the wind producer according to the intraday strategy (YR_{ID}) and compare it with the yearly revenue in the lower limit situation (YR_{LL}). In theory, the YR_{ID} would exceed the YR_{LL}, since in the intraday situation the wind producer was given the opportunity to adjust the day-ahead schedule in the intraday sessions, at more favourable prices than the balancing ones. However, that was not verified in two scenarios, and in those in which the YR_{ID} exceeded the YR_{LL} the difference was not as accentuated as it was expected (it was never superior to 0.2 M€). This occurred mainly due to the inaccuracy of the wind power forecasts utilized to perform the corrections in the ID markets. Actually, both NWP and ARMA models used in this study had some drawbacks. The NWP forecast did not contain information related with persistence, while the ARMA model had some negative aspects regarding the training period. These two issues made it impossible to extract the maximum potentialities of both methodologies. Nevertheless, once the NWP methods have a better behaviour for time horizons superior to 3 hours and ARMA models are likely to offer accurate forecasts within a time horizon of 30 minutes to 3 hours, we anticipate that the optimal strategy for wind producers when participating in the power market would be to use NWP methods to execute the day-ahead schedule (DAS) and ARMA models to perform the intraday adjustments (IDS).

Once the forecasts that resulted from the application of both NWP and ARMA methods did not make it evident that the wind producer would benefit from the participation in the intraday markets, it was studied the impact that a forecast accuracy improvement would have in the yearly revenue of the wind producer. The outcome showed that the initial difference between the YR_{ID} and the YR_{LL}, 0.2 M€, could rise to over 2 M€, which is a significant gain for the wind producer.

Last but not least, it should be highlighted that there is a limit for the valuation of the energy adjusted in the intraday market: balancing prices. It is a non sense for wind producers to adjust their position in the intraday sessions at prices that are more unfavourable that the ones they foresee for system operator's balancing prices.

Future Work/Further Studies

The study carried out in this thesis was applied to a single wind farm. However, further studies under this theme could address a group of wind farms. The foremost purpose of using more than one wind farm is to improve the overall forecast accuracy, due to a netting effect achieved in the joint operation. In effect, a downward deviation of one unit could be balanced by an upward deviation of other unit(s), if those two deviations could be netted out. For instance, suppose two wind farms, WF_1 and WF_2 that, in their last available schedule (it does not matter if it was in the LL or ID situation), predicted a generation of 50 MW for a particular hour each. Consequently, the sum of both forecasts was 100 MW. Yet, WF_1 was only capable of generating 40 MW, which would lead to an individual deviation of -10 MW in that hour. On the opposite, WF_2 had an actual generation of 60 MW, resulting in an individual netting of 10 MW. However, despite neither of the wind farms matched, separately, its last available schedule with the correspondent actual generation, they did so together and the global netting was null. All in all, they managed to accomplish in group an assignment they would fail individually.

One may now be thinking that implementing this idea would only be possible in wind farms that belong to the same wind producer or company, which would only apply to big producers that own several wind farms. However, small wind producers could also put into practise this strategy, for example, through an entity responsible for the market operation management of a set of wind units. In reality, this idea is already implemented in Spain, for instance, where there are entities responsible for managing the generation interface with the market for a group of wind farms. Note that for the referred strategy to be effective the geographical distribution is extremely relevant since grouping several wind farms of different parts of the country assures that different weather conditions (in particular wind speed) are covered in the same period of time. This leads to even more accuracy in the global netting.

Furthermore, another relevant area that can be explored as an extension of this work is studying how wind producers can reduce their exposure to price volatility. Within this field, future and forward markets assume a key role, as wind producers can hedge their position in the day-ahead and intraday markets through long term contracts. Like that, wind producers would reduce significantly their exposure to price fluctuations because they could set the minimum price at which they were disposed to sell their generation, for example on a year-ahead basis.

In addition, another aspect to take into consideration in further works is the possible implementation of the Spanish economical regime, denominated cap and floor, in Portugal. As a matter of fact, this retribution methodology will also reduce the exposure of wind producers to price fluctuations, since the price at which the energy produced by wind farms is valued will be bounded by a lower limit, or floor, and an upper limit, or cap[44]. Consequently, if the day-ahead price plus the unconstrained premium is inferior to the floor, the energy produced by wind farms is valued at the lower limit. In case the day-ahead market price plus the unconstrained premium exceeds the cap, the energy generated by the wind farm is valued at the maximum of two values: the upper limit or the market price. Between those two limits, the producer receives the market price plus the referred unconstrained premium.

Moreover, according to the decree law number 225/2007, renewable energy units will be remunerated not only for the selling of energy in the power market, but also for the selling of green certificates, which was not brought into play in this work. Thus, further studies under this theme should develop the issue of green certificates and in what terms will they become a complement to the financial income that wind producers will get from selling the energy in the power market.

Finally, as this thesis was focused in wind power, it would be profitable to extend this work to other renewable energy sources, namely photovoltaic and hydro power plants, in order to foreseen their inclusion in the electricity wholesale market.

[44] The cap only applies to a band of the market price. For high market price values, the generators receive the market price, which may exceed the cap.

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Appendix A

This appendix concerns the main features of OMIP.

A.1 OMIP

OMIP is the managing entity responsible for the organization of MIBEL's Portuguese division, ensuring the management of the MIBEL derivatives market, jointly with OMIClear (Energy Markets Clearing Company totally owned by OMIP), which performs the role of Clearing House and Central Counterparty. Thus, the management of the MIBEL derivatives market is carried out by two different entities:

- An exchange, managed by OMIP, which ensures the trading functions;
- A Clearing House, that takes on the central counterparty role within the market.

Although two companies exist, the organization is integrated in order to benefit from economies of scale and synergies, while still preserving the specificities of each entity. Figure A.1 shows this coexistence.

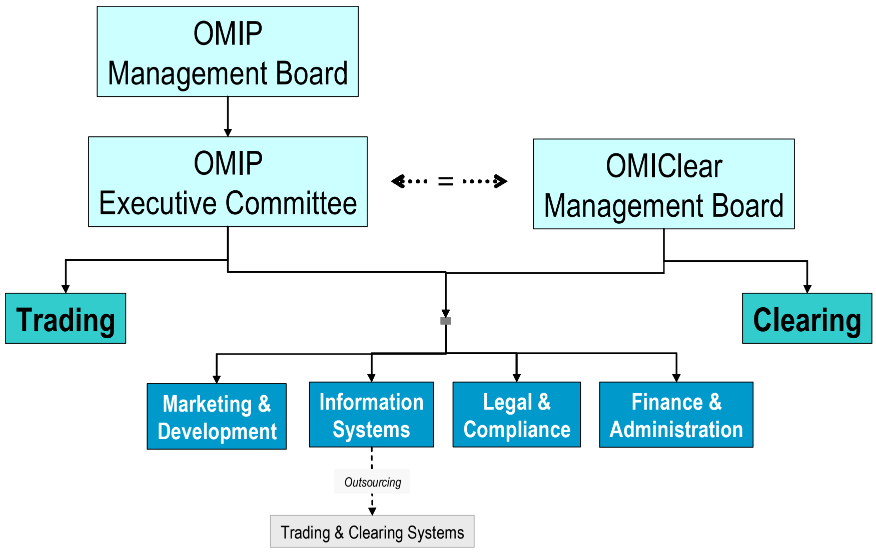

Figure A.1 – OMIP/OMIClear Internal Organization [11].

Although OMIP's incorporation as a company occurred in 2003, the MIBEL Derivatives Market was launched only in July, 2006.

The main goals of OMIP are the following:

- Contribute to the development of the Iberian electricity market;
- Promote Iberian reference prices;
- Supply clients with efficient risk management tools;
- Overcome some of the limitations of the Over the Counter (OTC) market.

As the managing entity responsible for the derivatives market trading platform, OMIP performs tasks necessary for the regular running of the market as the admission of participants, the supervision of the market participants behaviour, the implementation of disciplinary powers in relation to its members, the support of the registration of bilateral (Over the Counter – OTC) operations and the definition and listing of the contracts, as well as managing their trading. Furthermore, OMIP is also responsible for publishing information, which is relevant to the participants and the general public relative to the running of the derivatives market. OMIP's activities are based on a standard flexible market structure which involves an open electronic trading system with an open gateway to the clearing platform and allowing web based access, continuous and auction trading modes, and contracts with cascading. Membership is allowed to electricity companies as well as financial entities [11].

A.2 MIBEL's future contracts and future markets

Futures contracts are standardized contracts traded on commodity exchanges where all terms associated with the transaction have been defined in advance, leaving price as the only remaining point of negotiation. In this type of markets, a clearing house is present and plays the role of a central counterparty for all transactions.

Futures contracts are traded on OMIP. The products that are traded in this type of market are illustrated in Figure A.2.

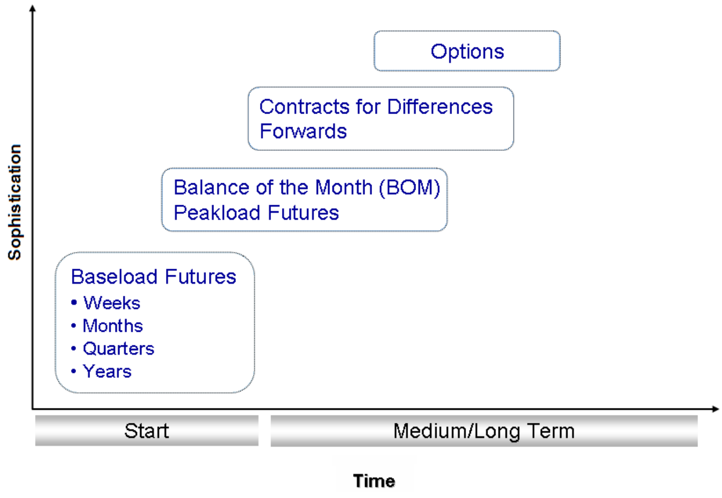

Figure A.2 – Products traded in OMIP's futures [11].

OMIP has two types of futures contracts: physical delivery contracts and financial delivery contracts. After a trade is matched, OMIClear becomes the buyer to every seller and the seller to every buyer. Consequently, benefiting from OMIClear's central counterparty role, it is possible to provide a common order book for both contracts. The only restriction is that the trades concerning physical delivery contracts must be registered in physical trading accounts and the ones for financial delivery contracts must be allocated to financial trading accounts [11].

During the trading phase, both contracts have the same procedures. However, during the delivery, the physical delivery positions are sent to OMEL to be integrated in the day-ahead market, and delivered. The financial movements with OMIClear are exactly the same for both contracts, assuring a financial balance, which allows them to profit from the same order book.

The trading period of a futures contract tradable on OMIP is the period in which trading members can trade such contract on the trading platform. Therefore, the trading period of a given contract is the period comprised between the First Trading Day (FTD), which sets the date when the contract life starts and is tradable, and the Last Trading Day (LTD), which must be previous to the start of the delivery period.

The delivery period corresponds to the period in which the electricity power of the underlying futures contract is delivered or consumed. Delivery periods can be weeks (Week Futures), months (Month Futures), quarters (Quarter Futures) or years (Year Futures). As the trading period, the delivery period of a given contract is the period comprised between the first day of the delivery period (FDD), which sets the date when the contract starts to be settled, and the last day of the delivery period (LDD), which sets the date when the contract delivery expires.

In terms of financial liquidation, on futures contracts there are two processes of daily settlement of profits and losses, one during the trading period and other during the delivery period. During the first period, OMIP defines a Settlement Price (SP) for each futures contract which corresponds to its fair market price. The difference between the settlement price of the current trading session and the settlement price of the previous trading session is credited/debited to the trading participant (via Clearing Member's accounts) in cash, through a process called Mark-To-Market (MTM). During the delivery period, there is also a daily cash settlement for both contracts with physical delivery as well as for contracts with financial delivery. However, this settlement results from the price differences between the day-ahead reference price and the Final Settlement Price (DAP on the LTD, i.e. upon maturity) of the futures contract, applicable to the number of hours of each day during the delivery period. Figure A.3 illustrates a financial liquidation of a futures contract.

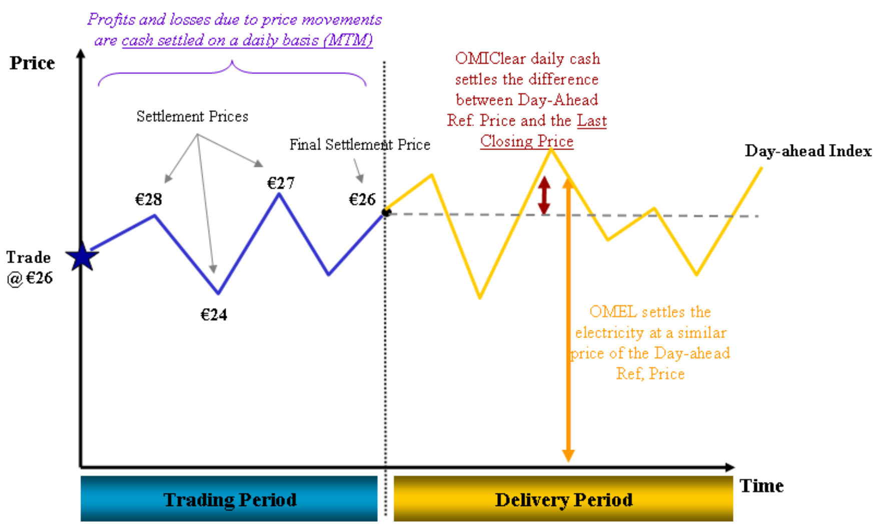

Figure A.3 – Financial settlement of a futures contract [11].

Particularly, the liquidation that is done during the delivery period is denominated the Delivery Settlement Value (DSV). The DSV is calculated according to (A.1).

$$DSV_d = H \times \sum_{i}^{n} [FP_i \times (DRP - FSP_i)] \tag{A.1}$$

Where:

DSV_d is the delivery settlement value for "d" delivery day (it may be a positive/negative value);

H is the number of delivery hours on “d” delivery day (23, 24 or 25);

DRP is the Day-ahead Reference Price for “d” delivery day;

FSP is the Final Settlement Price of futures contract “i”;

FPi is the Final Position on futures contract “i”;

i is the futures contract with delivery on “d” day;

n is the total number of futures contracts with delivery on “d” day.

Last but not least, it is important to know how futures contracts are delivered on MIBEL. Indeed there are two types of contract delivery: Physical Delivery and Financial Delivery. The delivery process starts on the last trading day of the futures contract for every position kept open at the end of the trading session. As it would be expectable, MIBEL baseload physical futures are subject to physical delivery and MIBEL baseload financial futures are subject to financial delivery.

Physical delivery involves two processes, the financial settlement and the physical settlement. The financial settlement was already mentioned, the physical settlement is concluded with the sending of open positions to OMEL, to be integrated in the day-ahead market process for physical delivery. Figure A.4 clarifies this procedure.

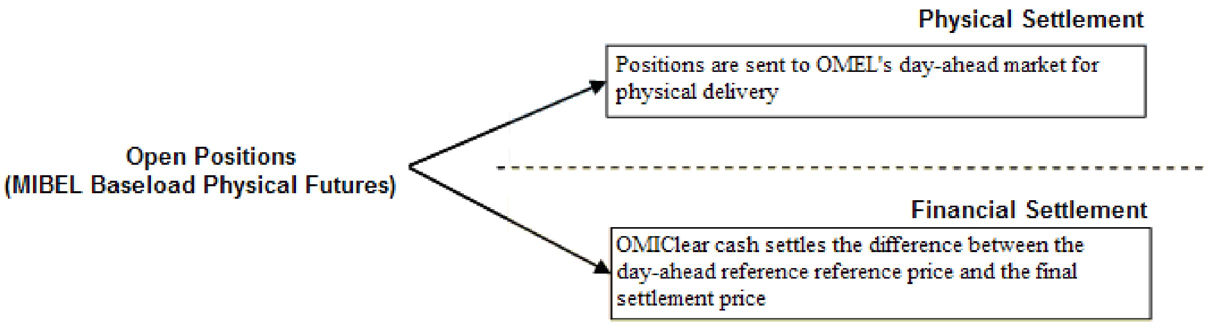

Figure A.4 – Physical Delivery [11].

The financial delivery comprises only the financial settlement process.

A.3 MIBEL’s forward contracts and forward markets

Electric power has long been purchased and sold under forward contracts. In the global perspective of financial markets, forward contracts are described as bilateral agreements to purchase or sell a certain amount of a commodity on a fixed future date (delivery date) at a predetermined contract price. The seller of the forward contract has the obligation to deliver the commodity on the delivery date.

Many financial forward markets operate as it was described in the above paragraph. However, the European power market approach, and, particularly, the Iberian overview, is slightly different in the aspect that it is not mandatory to have physical delivery in forward contracts.

In March 2009, OMIP launched a clearing service for bilateral forwards contracts (OTC registration), with the same structure as that of MIBEL futures. These contracts arise from direct negotiation between the parties.

Comparing with futures, the main difference lies on the settlement of gains and losses, which in the case of forwards only occurs during the delivery period of the contracts and on a monthly basis.

Contrary to futures, the daily gains and losses in forwards contracts are not daily cash settled. Based on the settlement prices defined by OMIP, OMIClear establishes the corresponding clearing prices and calculates the Variation Margin (VM) in the forward positions which refer to the accumulated gains and losses as from the date of the original trade. For instance, taking into account Figure A.3, a contract traded originally at 26 €/MWh and with a final settlement price (FSP) of 26 €/MWh would result in a null gain. While in a futures contract there would be a daily settlement of prices, in a forward contract the financial liquidation would only occur in the LTD. Obviously, the final profit is exactly the same in both situations. The VM is calculated in the trading and delivery periods of the contracts. However, when the contracts are in delivery, the VM only considers the days which have not yet been delivered. Regarding the already delivered days, OMIClear calculates for each of these days the final gain and loss resulting from the difference between the respective day-ahead market price and the original trade price, using a similar formula to (A.1). The only dichotomy is that the DSV in the case of forwards is on a monthly basis.

A.4 Market strategies

Increased competition in wholesale and retail electricity markets is likely to lower electricity prices, but will also result in greater price volatility as the industry moves away from administratively determined, cost-based rates and towards market-driven prices. Price volatility introduces new risks for generators, consumers, and marketers.

In a competitive environment, some generators will sell their power in potentially volatile day-ahead markets and will be at risk if day-ahead market prices are insufficient to cover generation costs. Consumers will face greater seasonal, daily, and hourly price variability and, for commercial businesses, this uncertainty could make it more difficult to assess their long-term financial position. Finally, power marketers sell electricity to both wholesale and retail consumers, often at fixed prices. Marketers who buy on the day-ahead market face the risk that the day-ahead market price could substantially exceed fixed prices specified in contracts.

Electricity futures and other derivatives help electricity generators, consumers, and marketers manage, or hedge, price risks in a competitive electricity market. Futures contracts are legally binding and negotiable contracts that call for the future delivery of a commodity. In some cases, physical delivery does not take place, and the futures contract is closed by buying or selling a futures contract on or near the delivery date. In this section it will be demonstrated how market participants can use futures contracts to reduce their exposure to price volatility (hedging), or even to just have positive returns (speculation) [19].

A.4.1 Speculation

Speculators are participants who try to take financial advantage from the fluctuations of the price of a commodity in the futures market. We may wonder why any rational person might want to engage in this type of scheme. If the markets are sufficiently competitive and all participants have access to enough information, the forward price should reflect the consensus expectation of the day-ahead market price. Hence buying low in the hope of selling high would seem more like gambling than a sound business strategy. Therefore, to be successful as a speculator one needs an advantage over other parties. This advantage is usually being less risk adverse than other market participants. Shareholders in some companies expect stable but not extraordinary results. The management of these risk-averse companies will, subsequently, try to limit its exposure to risks that might reduce profits significantly below expectations. On the other hand, shareholders in companies that engage in commodity speculation hope for very high returns but should not be surprised by occasional large losses. The management of these risk-loving companies will therefore feel free to take significant risks in order to secure larger profits. A risk-averse company will usually accept a price somewhat worse than it might be able to get later in exchange for the security of getting a fixed price now. A speculator, though, will demand a better price in exchange for accepting to shoulder the risk of future fluctuations. In essence, risk-averse companies remunerate speculators for their willingness to buy the risk [15].

However, speculators themselves also reduce their exposure to risk. They do so by diversifying into markets for different commodities. Even though speculators make a profit from their own trades, the market as a whole benefits from their activities because their presence increases the number and diversity of market participants. Participants who produce or consume a commodity thus find counterparties for their trades more easily. This increased liquidity helps the market discover the price of a commodity.

There are two types of speculation, short and long. To distinguish one from the other, let us introduce two simple examples. Suppose that a certain market player is forecasting a significant drop in the electricity prices for the coming month (e.g. December), given a strong estimated increase in the precipitation levels. Consequently, he attributes a low probability of rising prices. Facing this scenario, this player can sell December futures at OMIP and as long as the forecasted price is lower than the original selling price, he will register gains. Surely, the higher the risk and uncertainty in the forecasting, the higher will be the price at which the speculator is willing to sell in futures market. This is a typical example of short speculation. Short speculators are crucial to avoid unfair excessively high prices in the markets.

Now consider a market player that is expecting electricity prices to increase, due to a combination of several factors, including strong demand and increase in the price of natural gas and carbon. He, therefore, attributes a low probability of decreasing prices. In this situation, the market participant can buy futures at OMIP and as long as the forecasted price is higher than the original buying price, he will register gains. This example corresponds to a common case of long speculation. Long speculators are vital to avoid unfair excessively low prices in the markets. The higher the risk and uncertainty in the forecasting, the lower the price at which speculators are willing to buy in futures markets. It is relevant to mention, though, that in both short and long speculation, market players do not necessarily need to use futures contracts with physical delivery. On the contrary, they tend to prefer financial delivery, to avoid any risks connected with the supply (or withdrawal) of the commodity that they don’t include in their business model.

A.4.2 Hedging

Most derivatives function like a side bet on commodity prices. They are a zero sum game where there is a loser for every winner. The seller of a future or an option loses one euro for every euro that the purchaser earns. But this does not mean that risk is a zero sum game. All parties in a futures market could be hedgers, and all could be successfully using the market to reduce their risk [19].

Just like in the case of speculation, there are also two types of hedging. A short hedger sells futures to hedge a long position in the underlying commodity (electricity), while a long hedger buys futures to hedge a short position in the underlying commodity. A generator is long in electric power and will use a short hedge. A marketer who has sold power to a utility is short in power because he cannot produce it. A marketer will buy futures to hedge its short position in the power market. To clarify these procedures, two examples will follow.

In November 2009, suppose a producer with a 400 MW CCGT plant wants to obtain protection against low electricity prices during the next year (he already fixed his costs of natural gas). Therefore, he decides to hedge 50% of the exposure selling 200 CAL–10[45] futures at 40 €/MWh. Two typical scenarios may now happen for the day-ahead market prices in 2010:

- Day-ahead market prices become unexpectedly high, with an average of 43 €/MWh. As a result, producer sells at higher prices in the day-ahead market but losses 3 €/MWh in the futures market. In this situation, the average selling price, ASP_1, will be 41.5 €/MWh, as it is demonstrated in (A.2).

$$ASP_1 = 0.5 \times 43 + 0.5 \times 40 = 41.5 \text{ €} / MWh \qquad \text{(A.2)}$$

- Day-ahead market prices are unexpectedly low, with an average of 35 €/MWh. The producer, subsequently, sells at lower prices in the day-ahead market but gains 5 €/MWh in the futures market. In this scenario, the ASP_2 will be 37.5 €/MWh as it is proved in (A.3).

$$ASP_2 = 0.5 \times 35 + 0.5 \times 40 = 37.5 \text{ €} / MWh \qquad \text{(A.3)}$$

Had the producer wanted to completely eliminate the risk exposure to electricity price changes, he could sell 400 annual contracts and the average selling price would be exactly 40 €/MWh, irrespective of the day-ahead market price evolution. Figure A.5 illustrates the hedging scheme of the producer in this particular example.

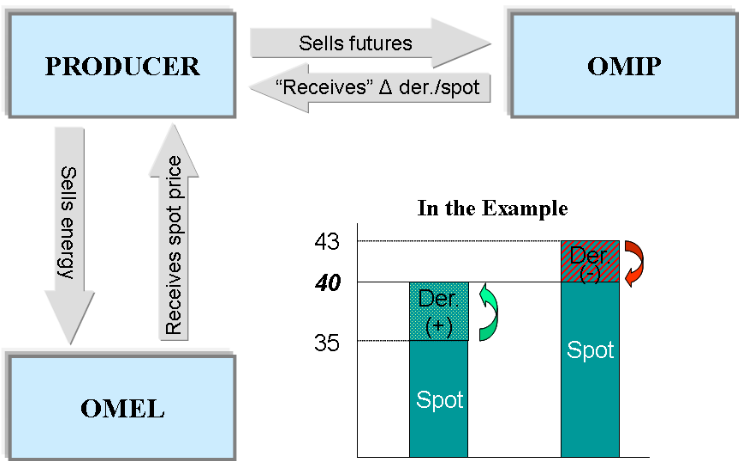

Figure A.5 – Producer's hedge [20].

Figure A.5 clearly shows that if the producer sells 400 annual contracts he will have a perfect hedge, i.e. he will be able to sell the energy at a fixed price of 40 €/MWh during the whole year, independently of the day-ahead market price fluctuations. If the day-ahead price is higher than the settlement price established on the futures contract, the producer wins on the day-ahead market but loses on OMIP. On the contrary, he loses on the day-

[45] Contract for the selling of energy during the year of 2010.

ahead and receives from OMIP. However, for the producer the only thing that matters is the final price at which he gets paid for the selling of energy, and that he already achieved when he sealed the futures contract.

Consider now the situation of a certain marketer that is worried with the bullish trend in the day-ahead market prices in the upcoming months as that will imply deterioration in its margin. Let us assume that he has already fixed prices with clients representing around 100 MW. He decides, therefore, to hedge the exposure buying 100 Q4 futures contracts at 41.60 €/MWh. Once again, two typical scenarios may happen for the day-ahead market prices in Q4:

- Day-ahead market prices are unexpectedly high, with an average value of 45 €/MWh for instance. In this case, the marketer will have increased costs with acquisitions in the day-ahead market. However, those will be compensated with gains in the futures market (3.4 €/MWh). The average buying price,ABP_1 , will be 41.60 €/MWh, corresponding to the difference shown in (A.4).

$$ABP_1 = 45 - 3.4 = 41.60 \ \text{€} / MWh \tag{A.4}$$

- Day-ahead market prices are unexpectedly low, with an average price of 35 €/MWh for example. Consequently, the marketer will have lower costs with the acquisitions in the day-ahead market. Nevertheless, he will not be able to profit from that as he will register losses in the futures market (6.6 €/MWh). The ABP_2 resulting from this operation will be 41.60 €/MWh, resulting from the sum shown in (A.5).

$$ABP_2 = 35 + 6.6 = 41.60 \ \text{€} / MWh \tag{A.5}$$

Just like the generator example, we come to the conclusion that the marketer is invulnerable to day-ahead market prices fluctuations. He just cares of buying a futures contract at a price that he considers profitable for himself. The settlements that afterwards take place are totally indifferent for the marketer because the buying price for him will never change. It is important to mention, though, that this is only a simplified example as it ignores second order cash flow effects and assumes the marketer is able to systematically buy at the day-ahead reference price.

Table A.1 summarizes the hedging strategies for both a marketer (consumer/retailer) and a producer.

Table A.1 – Hedging strategies [20].

	Consumer / Retailer	**Producer**
Physical Position	"Short" – Risk: higher prices	"Long" – Risk: lower prices
Futures Hedging	Buy Futures (Long hedging)	Sell Futures (Short hedging)
Higher Day-ahead Prices Scenario	Day-ahead Results ↓ Derivatives Results ↑	Day-ahead Results ↑ Derivatives Results ↓
Lower Day-ahead Prices Scenario	Day-ahead Results ↑ Derivatives Results ↓	Day-ahead Results ↓ Derivatives Results ↑

It is clear on Table A.1 the advantages both consumers and producers have in using hedging strategies. A consumer is typically short in energy, because he does not produce it, so he buys futures to hedge his position. If the day-ahead market prices are higher than expected, he will have a loss on OMEL. However, that loss will be totally compensated with a gain in the derivatives market. This is the meaning of the orange and blue arrows, respectively. When a lower day-ahead market prices scenario is faced, it happens all the way around. The consumer profits on OMEL but has to pay on OMIP. A producer, on the opposite, is long in energy so his hedging strategy covers selling futures on OMIP. Higher day-ahead prices scenario, in comparison with the price established in the contracts he sold on OMIP, will result in a gain for the producer. However, he will lose on OMIP. In a lower day-ahead prices scenario, the gain will be on OMIP and the loss on OMEL.

In conclusion, speculation is the opposite of hedging. It increases risk but holds out the possibility of gains from earning a risk premium. As it was discussed, speculation can result in extremely large financial losses and gains but is crucial for market liquidity. All in all, market strategies are a vital tool for market participants and wind producers, by the time they enter in the power market, should use hedging strategies in order to reduce their exposure to price volatility. For this reason, it is expected a continuous increase in the use of electric rate derivatives.

Appendix B

This appendix exemplifies the application of the pro-rata methodology with 3 situations of possible bid-ask curves.

Situation 1

In the first situation, there are two or more bid orders that cannot be totally filled.

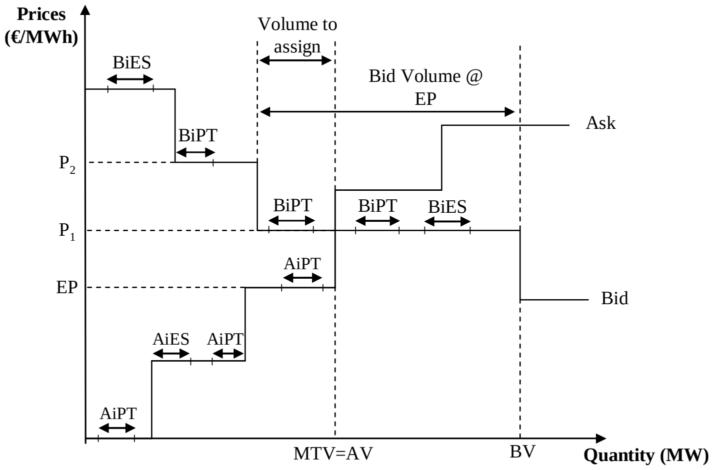

Figure B.1 – Situation 1 – Bid-Ask curve.

It is important to specify the meaning of some of the variables in Figure B.1:

P_1 – Last matched order price (lowest priority order matched);

P_2 – Penultimate matched order price;

BiPT – Portuguese purchasing order;

BiES – Spanish purchasing order;

AiPT – Portuguese selling order;

AiES – Spanish selling order.

It is clear in Figure B.1 that the bid volume exceeds the MTV, while the ask volume equals the MTV. Consequently, the bid volume (BV) will be subject to pro-rata. The second step in the pro-rata method is the calculation of the volume to assign. In this situation, the VA is computed as

$$VA = MTV - TV(P_2)\ . \tag{B.1}$$

To conclude the pro-rata methodology, it is necessary to determine the amount of the VA each bid at EP will be granted. That amount will be proportional to the volume of each bid, i.e. the bigger the volume of each bid at EP, the bigger the volume it will be assigned to it. The expression used to calculate the volume assigned to each bid at EP, VAB, shows that proportionality:

$$VAB = \frac{Bi@EP}{BidVolume@EP} \times VA\ . \tag{B.2}$$

Situation 2

This situation is characterized by two or more aks that cannot be totally filled.

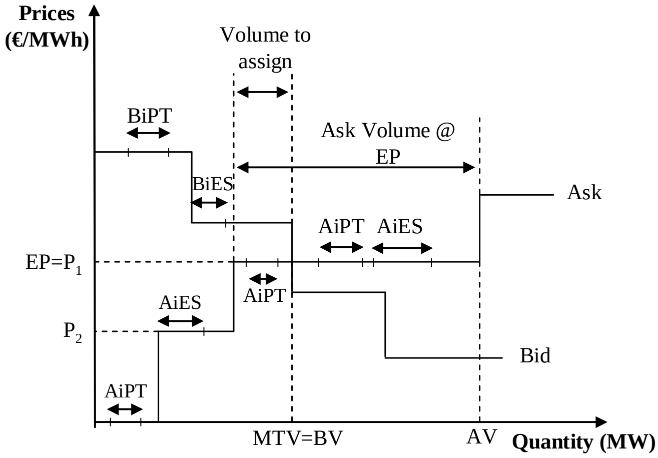

Figure B.2 – Situation 2 – Bid-Ask curve.

As in situation 1, P_1 and P_2 are, respectively, the last matched order price and the second last matched order price.

In this case, the ask volume exceeds the MTV. Consequently, the selling orders at EP will not be totally fulfilled. The VA in this situation is determined identically to (B.1). The volume assigned to each ask at EP, VAA, is calculated according to (B.3).

$$VAA = \frac{Ai@EP}{AskVolume@EP} \times VA \tag{B.3}$$

In the majority of occasions the VAA and the VAB are not integer numbers, and a rounding mechanism must be used, which is the following:

1. First VAA or VAB values are truncated;
2. The difference between VA and the sum of the resulting truncated orders (bids or asks) is computed;
3. The difference to fulfil the value of VA is completed by adding 1 MW[46] to VAA or VAB, in an ascending order according to their volume. If two values are identical, a random mechanism is used.

An example will clarify this procedure: imagine that the volume to assign is 100 MW and the ask volume at EP is filled by three selling orders of 100 MW each. The sum of the volumes of each ask at EP is 300 MW, yet the volume to assign is only 100 MW. Applying the pro-rata method, each ask would be assigned 33.33(3) MW, as it is shown in (B.4).

$$VAA = \frac{100}{300} \times 100 = 33.33(3)\ MW \tag{B.4}$$

However, truncating each ask, would result in a VAA of 33 MW. The sum of the three truncated selling orders would be 99 MW and 1 MW would be missing to fill the VA. Likewise, that MW is summed to the ask that has

[46] In this work, the minimum order size considered was 1 MW, instead of 0,001 MW as in OMEL. 1 MW is the standard minimum unit used in the wholesale power market.

the lowest volume. In this case, as the volume is identical in all three selling orders, it is indifferent the order that is granted the extra MW, and the referred random mechanism is applied.

Situation 3

Figure B.3 illustrates a special situation.

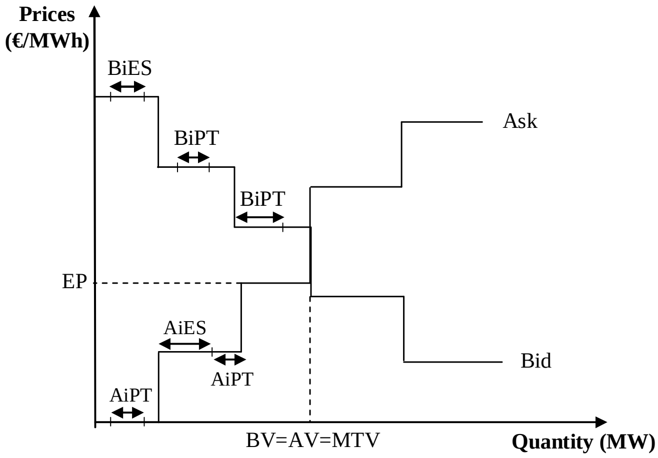

Figure B.3 – Situation 3 – Bid-Ask curve.

In fact, as the bid volume and the ask volume equal the MTV, there is no need to apply the pro-rata methodology. In this case, all bid and ask orders are satisfied, i.e. all volumes declared in each bid or ask are matched.

Appendix C

This appendix explains the matching procedure between both forecasting models used in this work (NWP and ARMA models) and the several market sessions.

C.1 Matching NWP forecasts with market sessions

Building the data base stated in section 4.2.2 involved many previous calculations and considerations. Amongst them, matching the generation forecast of the wind farm with the several market sessions emerges as one of the most significant.

The generation forecast of the wind unit based on NWP models was kindly provided by REN for the realization of this study. Basically, for a particular day, let us call it D3, REN starts receiving generation predictions three days in advance. During the days that precede D3 (D0, D1 and D2), and even in the considered D3, REN is given four hourly basis forecasts that arrive at 06h, 12h 18h and 00h (CET-1), each of them comprising a prediction for the next 72 hours. With this scenario, a correspondence was made between the reception of the predictions and the gate closure time of each market session, taking into account the philosophy that only one correction is performed for each hour, with the last available information. Figure C.1 illustrates not only that matching but also the generation forecasts that REN is offered for day D3.

Day	Hour Per	D0-00	D0-06	D0-12	D0-18	D1-00	D1-06	D1-12	D1-18	D2-00	D2-06	D2-12	D2-18	D3-00	D3-06	D3-12	D3-18
D0	01-06	01-06															
D0	07-12	07-12	01-06														
D0	13-18	13-18	07-12	01-06													
D0	19-24	19-24	13-18	07-12	01-06												
D1	01-06	25-30	19-24	13-18	07-12	01-06											
D1	07-12	31-36	25-30	19-24	13-18	07-12	01-06										
D1	13-18	37-42	31-36	25-30	19-24	13-18	07-12	01-06									
D1	19-24	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06								
D2	01-06	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06							
D2	07-12	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06						
D2	13-18	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06					
D2	19-24	67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06				
D3	01-06		67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06			
D3	07-12			67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06		
D3	13-18				67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06	
D3	19-24					67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12	01-06
D4	01-06						67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18	07-12
D4	07-12							67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24	13-18
D4	13-18								67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30	19-24
D4	19-24									67-72	61-66	55-60	49-54	43-48	37-42	31-36	25-30
D5	01-06										67-72	61-66	55-60	49-54	43-48	37-42	31-36
D5	07-12											67-72	61-66	55-60	49-54	43-48	37-42
D5	13-18												67-72	61-66	55-60	49-54	43-48
D5	19-24													67-72	61-66	55-60	49-54
D6	01-06														67-72	61-66	55-60
D6	07-12															67-72	61-66
D6	13-18																67-72

Not a forecast

DAS of D3 ID2 of D3 ID3 of D3 ID5 of D3

ID1 of D4
(Note that the ID1 of D4 covers the last four hourly periods of D3, besides the 24 hours of D4)

Figure C.1 – Matching of the generation forecasts of the wind farm with the market sessions[47].

[47] The time reference in this Figure is CET-1.

Note that the data in gray in Figure C.1 is not a prediction and should be ignored for the case study. Consequently, the D0-00 information reaches REN at 06h, the D0-06 at 12h, the D0-12 at 18h and so on for the remaining entrances.

Analysing Figure C.1, it is clear that the first forecast for the first six hours of D3 arrives at 12h of D0. Six hours later, at 18h of D0 turns up a first correction for the first six hours of D3 and the first prediction for the next 6 hourly periods (07-12) of D3. At 00h of D1, the first prediction for the 13-18 hourly periods of D3 arrives, alongside with adjustments to the two previous periods (01-06 and 07-12). The first forecast that covers the full periods of D3 pulls in at 06h of D1. This procedure is uninterrupted until the end of D3.

The deadline for the sending of selling or purchasing orders to the day-ahead market concerning day D is 10:00 (CET) of day D-1. Therefore, the last available information for the wind producer to send his selling orders to the MO is the D2-00, which is completed at 06h (CET-1) of D2. The subsequent data, D2-06, arrives at a time the GCT for the daily market has already closed.

In Figure C.1 are also highlighted the forecasts that were used to attend the different intraday sessions. However, if we sum all the hours that are said to be used as corrective actions in the ID market, we rapidly come to the conclusion that it exceeds 24 hours. This happens because in Figure C.1 there are overlapping periods that are not used in corrective actions, because only one such action is performed for each hourly period. Having this in mind, Figure C.2 unambiguously discriminates the hours that are covered by the corrective action in each ID session.

Day		D2-00	D2-06	D2-12	D2-18	D3-00	D3-06	D3-12	D3-18	
D2	CET-1									CET
D2	24	24	18	12	6					1
D3	1	25	19	13	7	1				2
D3	2	26	20	14	8	2				3
D3	3	27	21	15	9	3				4
D3	4	28	22	16	10	4				5
D3	5	29	23	17	11	5				6
D3	6	30	24	18	12	6				7
D3	7	31	25	19	13	7	1			8
D3	8	32	26	20	14	8	2			9
D3	9	33	27	21	15	9	3			10
D3	10	34	28	22	16	10	4			11
D3	11	35	29	23	17	11	5			12
D3	12	36	30	24	18	12	6			13
D3	13	37	31	25	19	13	7	1		14
D3	14	38	32	26	20	14	8	2		15
D3	15	39	33	27	21	15	9	3		16
D3	16	40	34	28	22	16	10	4		17
D3	17	41	35	29	23	17	11	5		18
D3	18	42	36	30	24	18	12	6		19
D3	19	43	37	31	25	19	13	7	1	20
D3	20	44	38	32	26	20	14	8	2	21
D3	21	45	39	33	27	21	15	9	3	22
D3	22	46	40	34	28	22	16	10	4	23
D3	23	47	41	35	29	23	17	11	5	24
D3	24	48	42	36	30	24	18	12	6	25

Not a forecast

DAS of D3 ID2 of D3 ID3 of D3 ID5 of D3

ID1 of D4
(Note that the ID1 of D4 covers the last four hourly periods of D3, besides the 24 hours of D4)

Figure C.2 – Hourly discrimination of the matching between the generation forecast and the different market sessions.

Figure C.2 can be interpreted as a complement to Figure C.1. As a matter of fact, it is an hourly detail of the coloured areas in Figure C.1, after having removed the overlapping periods. Furthermore, in Figure C.2 it is also made the correspondence between the Portuguese hours (CET-1) and the Spanish ones (CET). This is a vital step in the algorithm because both the day-ahead market and the ID markets are run by OMEL using CET time. Consequently, there needs to be an adjustment between the schedules of the wind farm and the deadlines of the several market sessions. This fact will have to be seriously taken into account by the Portuguese wind power producers when they enter the power market.

The matching between the generation forecasts and the ID sessions was accomplished according to the idea of correcting just once the forecast that was sent to the day-ahead market, on the last opportunity to do so, i.e. as close to real time as possible. Theoretically, this would mean that the power adjustments are effectuated with the best available forecast.

To meet this idea, the matching was realized backwards, with the following steps:

- The last four hourly periods (21-24) were assigned to the first intraday session of the following day (ID1 of D4), which actually covers the last four hours of the covered day[48]. Both schedules are compatible because the GCT of this particular ID session is at 17:45h (CET[49]) of D3 and the forecast used, D3-06, is completed at 13h;
- Hourly periods 12 to 20, inclusively, were assigned to ID5. Again, there is no incompatibility between the GCT of ID5, 08:45h of D3, and the arrival time of the forecast D3-00, 07h of D3;
- Hours 5 to 11, inclusively, were assigned to ID3. The GCT of this ID session is 01:45h of D3 and the forecast used is D2-18, which is finished at 01h of D3. Once more, both deadlines are well-matched;
- The first four hours were assigned to ID2. The GCT of ID2 is at 21:45h of D2 and the forecast utilised is D2-12, which is completed at 19h of D2. Over again, both schedules are well-suited.

Figure C.3 illustrates the above stated matching procedure from the market's perspective.

[48] The first intraday session (ID1) of day D covers 28 hourly periods: the last four of day D-1 plus 24 of day D.
[49] From this point forward, if nothing is said in contrary, the reference time is always CET.

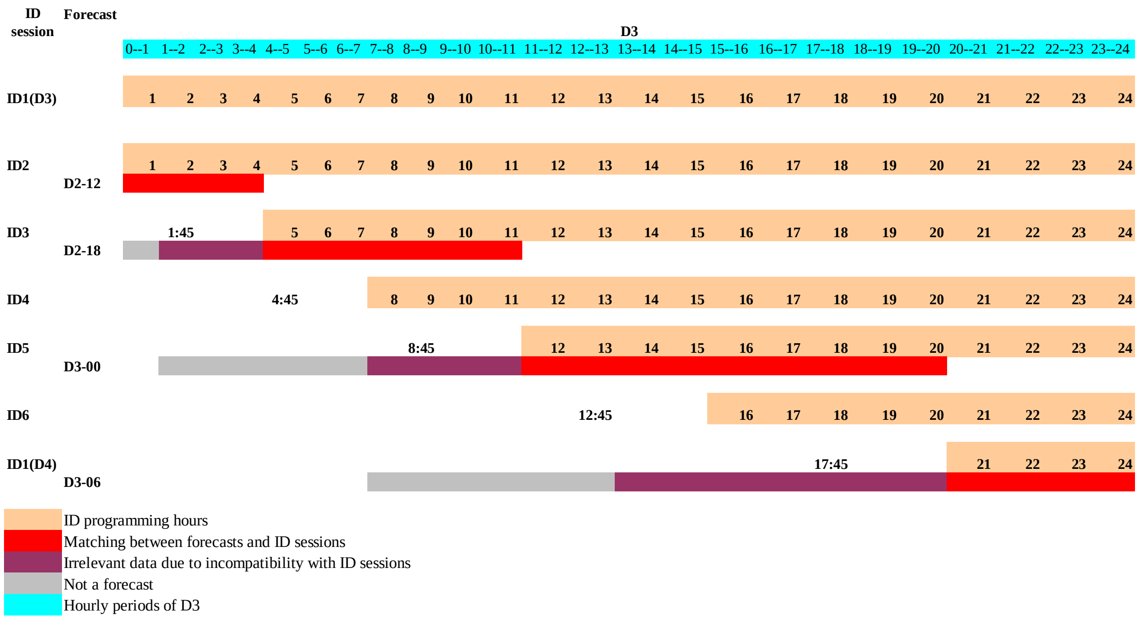

Figure C.3 – Market's perspective of the correspondence between the forecasts and the different ID sessions.

Due to lack of space it was impossible to represent D2 in Figure C.3 and, subsequently, the gate closure times of both ID1 and ID2. Nevertheless, they are referred in Figure 2.18 of chapter 2.

Moreover, as one may notice in Figure C.3, ID4 and ID6 were not necessary, both for the same reason. Regarding ID4, by the time of its GCT, 04:45h of D3, the most recent forecast had already been assigned to ID3. Consequently, there was no reason to reprogram the same hours with the same predictions. Identical situation happens with ID6 as by the time of its GCT, 12:45h of D3, there was not any newly forecast besides the one that had been previously assigned to ID5.

C.2 Matching ARMA forecasts with ID sessions

Before building the ARMA model, it was necessary to choose how many hours backwards were going to be considered in order to train the model (training period). Ideally, the training period for the forecast of the power of the wind farm in 2008 would be its AG of 2007. However, in the absence of that information it was assumed that the AG of December 2007 was identical to the AG of December of 2008. Therefore, the training period considered were 744 hours.

Nonetheless, this training period is dynamic, meaning that it is successively actualised with the actual generation of 2008. Figure C.4 illustrates that actualisation as well as the matching between the ARMA forecast and the ID sessions.

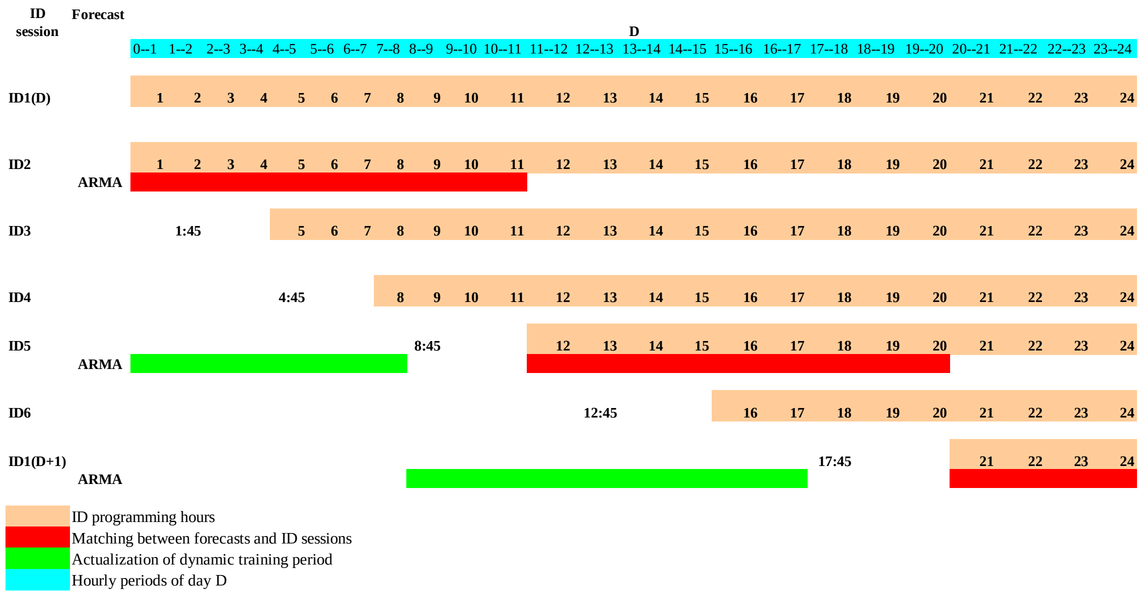

Figure C.4 – Matching between ARMA forecast and ID sessions for a general day D.

The explanation of the matching procedure and the actualization of the dynamic period is the following, assuming that day D of Figure C.4 is the first of January 2008: for the first dynamic period 744 hours are utilized, corresponding to the hours of December 2007, to train the model. The approach uses the previous 744 hours to fit the model parameters, after first identifying the order of the ARMA process. Firstly, an 11-hour forecast is generated and assigned to ID2. Then, the training period shifts forward by 8 hours and a 9-hour forecast is generated and assigned to ID5. Note that this forward shifting incorporates the AG of the wind farm in the first 8 hours of January, as information for dynamic period. One may question why the dynamic period is not actualized with the AG in the first 11 hours of January. However, that would only be an option if the GCT of ID5 was after 11:00h. After generating the forecast assigned to ID5, the training period shifts other 9-hours and the last four hours of the first day of January are forecasted. Subsequently, when we move to the generation forecast of day 2 of January 2008, the training period comprises, already, the AG verified in the first day of January. This is only possible, though, because it was assumed, in order to ease the implementation of the algorithm, that the GCT of ID2 was 00:00 of day D. The process continues for the entire year of 2008.

The ARMA model that better represented the time series, and consequently the one that was employed in the above mentioned process, was ARMA (2,1). This choice was based on the application of the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC) to a set of models[50], which can be observed in Table C.1. ARMA (2,1) was the model that had the smallest value of the AIC and BIC.

[50] Using MATLAB's aicbic function.

Table C.1 – AIC and BIC applied to the wind power time series.

ARMA(p,q)	AIC	Ranking	BIC	Ranking
1,0	5.6219E+03	18	5.6357E+03	13
2,0	5.5875E+03	13	5.6060E+03	6
6,0	5.5785E+03	8	5.6154E+03	9
8,0	5.5799E+03	10	5.6260E+03	12
12,0	5.5868E+03	12	5.6514E+03	14
1,1	5.5772E+03	6	5.5957E+03	1
1,2	5.5738E+03	2	5.5969E+03	3
1,4	5.5765E+03	4	5.6088E+03	7
2,2	5.5749E+03	3	5.6025E+03	4
2,1	5.5729E+03	**1**	5.5959E+03	**2**
0,4	5.7640E+03	21	5.7917E+03	20
0,6	5.6603E+03	19	5.6972E+03	17
4,1	5.5768E+03	5	5.6091E+03	8
4,0	5.5780E+03	7	5.6057E+03	5
1,6	5.5802E+03	11	5.6217E+03	10
2,12	5.5901E+03	16	5.6639E+03	16
1,12	5.5881E+03	14	5.6573E+03	15
1,24	5.5944E+03	17	5.7189E+03	19
2,24	5.5889E+03	15	5.7180E+03	18
3,24	5.7588E+03	20	5.8926E+03	21
4,24	5.8741E+03	22	6.0125E+03	22
2,6	5.5794E+03	9	5.6255E+03	11