Impact of Large-Scale Integration of RES in Electric Power Systems

Exploration of the future European Electricity Market Design

Ainhoa Villar Lejarreta

Technische Universiteit Delft

Universidad Pontificia ICAI ICADE Comillas Madrid

European Commission ERASMUS MUNDUS

TU Delft Delft University of Technology

Challenge the future

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Economics and Management of Network Industries (EMIN)
Engineering and Policy Analysis (EPA)
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Ainhoa Villar Lejarreta

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Chair	Prof. Dr. Ir. P. M. Herder	Delft University of Technology
First Supervisor	Dr. Ir. R.A. Verzijlbergh	Delft University of Technology
Second Supervisor	Dr. Ir. G.A. Morales-España	Delft University of Technology
Third Supervisor	Dr. Ir. B. Enserink	Delft University of Technology

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SUMMARY

Until recently the European electricity system has been operating as a set of isolated national markets with divergent regulatory norms. Today, the day-ahead markets between South-Western Europe and North-Western Europe are fully coupled, enabling the trading of electricity all the way from Portugal to Finland. Moreover, policy-makers in the power sector are currently preparing the design of what it will be called the Internal Energy Market. Europe's power sector aims for an integrated, more competitive, secure and sustainable power system. Meanwhile, ambitious renewable targets aim for a decarbonization of the electricity sector by 2050. This will lead to a large deployment of renewable technologies into the system, with almost 50% of them being the most intermittent, uncertain and unevenly distributed sources in the continent, wind and solar.

The introduction of the projected large amounts of intermittent sources will impact both the functioning of the electricity markets and the operation of the transmission grids. Cross-border congestion profiles are expected to suffer changes, transmission constraints will appear and an effective congestion management approach will be needed within the framework of the market's redesign.

Currently, the congestion management mechanism in place in many Member States is based on a redispatch phase after market clearance, which results in inefficiencies and additional rebalancing costs. This congestion management approach falls within the zonal market design. A consistent integration of electricity markets across Europe enabling the access of large capacities of renewable generation would have the potential to maximize overall welfare to all agents. Generators would enter a more competitive market with a lower risk, consumers would benefit from lower electricity prices and transmission system operators would benefit from reduced operation costs of balancing and reserve.

Locational marginal pricing, also known as nodal market design, would be able to provide an integrated approach of national and international congestion management, a joint allocation of international transmission rights, the integration of congestion management with day-ahead, intraday and balancing markets and finally a transparent approach to facilitate secure and effective cooperation and information exchange among European system operators. However, a committed high-level support on a European level would be required for its further implementation.

The objective of this thesis is to gain a better understanding of the European power market in presence of large amounts of renewable energies and under different power market designs, and find out by how much can the market design and its features affect the provision of cost-efficient electricity, this is the system's variable generation costs of electricity.

In order to study the influence of the power market design in the integration of large amounts of renewable energies, an optimization model is used. The model solves a weekly unit commitment problem and the transmission constrained economic dispatch for the day-ahead market of a conceptual network of Europe and from a centralized decision making point of view. The model uses a mixed-integer linear programming (MILP) formulation of the unit commitment and minimizes total variable generation costs of the system. The two market designs studied, nodal market and zonal market, are modeled according to how congestion is managed in each case.

The aim is to analyze the impact of the power market design on the power system's variables: total variable generation costs, RES curtailment, energy production by technology, non-served energy and hourly electricity prices while subjected to several scenarios of increasing degree of RES integration. For this, different degrees of future RES scenarios based on ENTSO-E market studies are used.

The research shows that in a high renewable scenario the total variable generation costs of the power system when it operates under a zonal power market are around 0,32% higher than under a nodal market. These potential savings under a nodal market could even be larger especially if the large expected projections of renewable sources of generation finally materialize and provided that the required network capacities are delivered effectively on time.

Moreover, the degree of curtailment in both nodal and zonal markets rise notably in a high renewable scenario compared to the current situation, up to a weekly curtailment of 7,83% and 8,01%, respectively. Such notable amounts of curtailment could be due to the insufficient development of the transmission network assumed which leads to the incapability of supplying cheap renewable energy across wide regions and instead having to commit or reschedule local and more expensive technologies.

On the other hand, costs of unserved energy represent 2,95% and 3,08% of the total system's variable generation costs in the nodal and zonal market, respectively. It is again highlighted the importance of a timely delivery of the network infrastructure investments to gradually integrate the large deployment of renewables in the system.

Overall, a nodal market in Europe could have the potential of improving efficiency in the system by reducing variable generation costs by 0,32% compared to a zonal market. Benefits could increase even more if an adequate network expansion plan that takes into account the growth of renewable energies would deliver its investments on a timely manner.

PREFACE

This research thesis is the end point of the two-year Erasmus Mundus Master Programme Economics and Management of Network Industries (EMIN), carried out at the faculty of Technology, Policy and Management of the Delft University of Technology (Delft) and at the ICAI Engineering School of Comillas University (Madrid).

The research project presented below is aimed at everyone interested in electric power systems, in the integration of renewable energies and the design of power markets.

Upon completion of this thesis, I would like to thank the European Commission for giving me the opportunity to pursue the EMIN programme and allowing me to combine my studies in TU Delft and Comillas University. I would also like to appreciate professors in both universities for their valuable teachings in the fields of energy and policy analysis. In particular, I would like to thank my first supervisor Remco for his constant support and guidance and Germán for his valuable input in the preparation of this thesis, as well as Bert Enserink and Pauline Herder for their constructive feedback.

I also want to thank my friends Hugo, Shujie, Roxanne, Kevin, Donna, Hector, Hanif, Lien, Djong, Viet, Maria Luisa, Mariam and Tariq for their help and shared happiness during this time. Last but not least, I want to thank all my family, especially my dear parents for their continuous support and help at all times.

Ainhoa Villar Lejarreta, December 2015.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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NOMENCLATURE

A. Indexes and Sets

$g \in G$	Generating units, from 1 to G
$g \in G_1$	Generating units in G with minimum uptime equal to one hour
$gen_{i,g}$	Location of generating unit g in bus i
$p \in P$	Hourly periods, from 1 to P hours
$i \in I$	Network buses, from 1 to I (i and j are used indistinctly)
$i_{AC} \in I$	Subset of i, network buses connected to at least one AC transmission line
$i_{DC} \in I$	Subset of i, network buses connected only to HVDC transmission lines
$c \in C$	Power line circuits, from 1 to C
$ij_{AC\ i,j,c}$	Subset of ij, network buses i and j connected by an AC transmission line and circuit ID c
$l \in L$	HVDC lines, from 1 to L
$l_{DC\ l,i}$	HVDC line l from bus i (to bus j)

B. Parameters

1) Model parameters related to hourly periods:

$D_{p,i}$	Instantaneous demand in hour p and in node i [GW]
$\overline{IG}_{p,i}$	Maximum intermittent generation from wind and solar in hour p and in node i [GW]

2) Model parameters related to the generating units:

$\overline{P_g}$	Maximum power output of generating unit g [GW]
$\underline{P_g}$	Minimum power output of generating unit g [GW]

IP_g	Initial power output of generating unit g [GW]
IP_g^{min}	Initial power output of generating unit g above $\underline{P_g}$[GW]
IT_g	Initial time status of generating unit g, defined as the time the unit has been online [hours]
IS_g	Initial commitment status of generating unit g, which is equal to 1 if the unit is online and 0 if it is offline
RU_g	Ramp-up capability of generating unit g [GW/hour]
RD_g	Ramp-down capability of generating unit g [GW/hour]
TU_g	Minimum time online of generating unit g [hours]
TD_g	Minimum time offline of generating unit g [hours]
$C_g^{Variable\ Fu}$	Fuel cost of generating unit g [M€/GWh]
$C_g^{O\&M}$	Variable operation & maintenance cost of generating unit g [M€/GWh]
C_g^{MC}	Marginal cost of generating unit g [M€/GWh]
$C_g^{Fixed\ Fuel}$	Fixed fuel consumption cost of generating unit g [M€/hour]
C_g^{SU}	Startup cost of generating unit g [M€/GW]
C_g^{SD}	Shutdown cost of generating unit g [M€/GW]
E_g	Emission rate of generating unit g [tCO_2/GWh]
C^{CO2}	Cost of CO_2 emissions [M€/tCO_2]
C^{NSE}	Cost of non-served energy [M€/GWh]

3) Model parameters related to the network:

$X_{ij,c}$	Inductive reactance X of line ij and circuit ID c [p.u.]
sb	Slack Bus i= 2
B_{ij}	Susceptance B of line ij
Z_{ij}	Impedance Z of line ij. Inverse of B: Z = B^{-1}

$PTDF_{ij,c,i}$	Power transfer distribution factor for AC transmission line ij, circuit ID c and node i
$\overline{P}_{AC\ ij,c}$	Maximum power capacity of AC transmission line ij and circuit ID c [GW]
$A_{DC\ l,i}$	Incidence matrix: Incidence of DC line l and node i
$\overline{P}_{DC\ l}$	Maximum power capacity of HVDC line l [GW]
$LMP_{p,i}$	Locational Marginal Price (nodal price) in node i in hour p [M€/GWh]
λ_p	Dual variable of system balance constraint for every hour p [M€/GWh]
$\mu_{ij,p}$	Dual variable of the network constraint of the AC transmission line ij for every hour p [M€/GWh]
$\beta_{i,p}$	Dual variable of the power balance constraint in nodes i with only HVDC lines for every hour p [M€/GWh]

C. *Variables*

1) *Free and continuous variables:*

C^{Total}	Total variable generation costs [M€]. Objective function.
$pl_{AC\ ij,c,p}$	Power flow through AC line ij and circuit ID c in hour p [GW]
$pl_{DC\ l,p}$	Power flow through HVDC line l in hour p [GW]

2) *Positive and continuous variables:*

$p_{g,p}$	Power output of generating unit g in hour g [GW]
$p_{g,p}^{min}$	Power output of generating unit g above the minimum output $\underline{P_g}$ in hour p [GW]
$ur_{g,p}$	Operating upward reserve of generating unit g in hour p [GW]
$dr_{g,p}$	Operating downward reserve of generating unit g in hour p [GW]
$ig_{i,p}$	Intermittent generation from wind and solar in node i in hour p [GW]
$nse_{i,p}$	Non-served energy in node i in hour p [GW]

3) *Binary variables:*

$u_{g,p}$ Commitment status of generating unit g in hour p, which is equal to 1 if the unit is online and 0 if it is offline

$v_{g,p}$ Startup status of generating unit g in hour p, which is equal to 1 if the unit starts up and 0 otherwise

$w_{g,p}$ Shutdown status of generating unit g in hour p, which is equal to 1 if the unit shuts down and 0 otherwise

CHAPTER 1

INTRODUCTION

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1. Introduction

Until recently the European electricity system has been operating as a set of isolated national markets with divergent regulatory norms. The trend now is that these markets are unified into a single more efficient market. This requires solving a number of technical and regulatory problems.

Additionally, nowadays there is a growing concern about the environment in all different kind of fields. International institutions, governments and industries are gradually adopting more sustainable norms and practices in order to exploit resources at minimum cost. This trend can also be seen in the growth of renewable energies in the power system. They too present issues in regard to their integration into the system.

Chapter 1 exposes the path followed by the power systems in Europe, makes an appraisal of the technical and regulatory problems to be solved in the near future and identifies existing and alternative power market designs that would contribute to a more economically efficient and transparent European electricity market.

1.1. Europe's Future Power System. Problem in context.

Nowadays, Europe's Power System is immersed in an energy transition period. Policy-makers in the power sector are currently envisioning the future power system of what it is lately being called an Energy Union for Europe. Consultations to experts and stakeholders, and legislative proposals are being put forward for what it will be the biggest redesign of Europe's electricity market.

Short after the liberalization process of national energy markets around the 1980s started, driven largely by economic reasons, the European Union already engaged in a broader approach to the restructuring of the power markets in the Member States. Setting aside the economic national goals of every individual country in the region, the European Union focused on the strategic and political concerns involving the power sector. The high dependency of the Union on external sources of oil and gas prompted the following three pillars which are still the basis of today's energy needs: secure an increasing supply of energy from domestic and foreign sources, develop a more competitive European energy market and support environmental protection and the development of renewable energy sources (Barroso, 2006). With these goals in mind and following several European Directives in the 1990s that favoured the liberalization of markets, the grounds for the creation of a single European energy market were established.

However, the restructuring process of the different national markets towards a more competitive and efficient one turned out to take longer than expected for several reasons. (Pollitt, 2009) argues that the privatization of state-owned electricity assets, the opening of the market to competition, the vertical unbundling of transmission and distribution activities from the generation and retailing services and the introduction of an independent regulator are all four stages that should be completed in advance for a successful implementation of a market-based reform. Nevertheless, a continuous process of interactions between market players and regulatory authorities in all Member States took place revealing the complexity to reach the same level of development of all stages in the different countries. Technical, economical and political barriers towards competitive markets explain the delays and the difficulties in the process of the reform (Karan & Kazdagli, 2011).

Technical barriers are related to the characteristics of the commodity of electricity. Electricity depends on a physical grid that reduces liquidity and adds complexity to the operation of markets. Close coordination is required between the operators of different networks for energy trade to happen and is well-known that every power system has certain market arrangements that differ from one another, inevitably running into numerous obstacles.

From the economical and political point of view, national governments are reluctant to give up complete control over national energy markets due to the importance of security of supply and the energy sector on the economic development of the rest of the industries. This situation avoids effective competition from taking place and hence inefficiencies appear, such as the need to introduce state subsidies to keep an industry functioning (Karan & Kazdagli, 2011). Moreover, the generation mix in every country is extremely different. Some countries might rely more on a specific technology than another and this, together with EU mechanisms implemented supporting certain technologies over others, might emphasize price differences among regions, certainly giving way to uneven distributions of the gains and, thus, rising uneasiness in governments to further integrate in a common electricity market.

Despite these barriers, considerable progress has been made thanks to the efforts of stakeholders and the European Commission, the main driving force and main policy maker in this energy reform. Relevant milestones have been achieved. Today, the full price coupling of the day-ahead markets between South-Western Europe and North-Western Europe is in place enabling the trading of electricity all the way from Portugal to Finland. Similarly, on-going progress is taking place in Eastern Europe. Moreover, a centralised information platform has been made available by the European Network of Transmission System Operators for Electricity (ENTSO-E), where data about electricity markets is published, aiming for greater transparency among all market players.

Complementarily to the market coupling initiatives, an updated investment plan for network expansion was released by the ENTSO-E in its Ten-Year Network Development Plan (TYNDP) 2014, in which a total investment of 150 Billion Euros is predicted until the year 2030. In this regard, only two thirds of the infrastructure projects are being delivered on a timely manner. Transmission System Operators (TSOs) are facing challenges due to permit procedures or lack of public acceptance. However, the ENTSO-E emphasizes in its plan the benefits that greater interconnections would bring to all market players by achieving greater convergence in electricity prices between regions as well as a significant reduction in these (ENTSO-E, 2014).

Again, committed political support is of utmost importance to achieve a proper European integrated market.

While in the past years focus in the energy sector shifted from liberalization to the integration of the national markets, more specifically to the coupling of the day-ahead energy markets, the priority for the future years is set on decarbonisation policies, security of supply and the integration of markets closer to real-time like intra-day and balancing markets.

The European Union's renewable energy directive from 2009 is boosting investments in renewable technologies in such amounts that has caused struggles to conventional generation, grid operators and regulators to effectively respond to ever-increasing uncertainty levels in the power system. Given the ambitious environmental energy targets set for 2050, for which European power systems will have to reduce its contribution to greenhouse gas (GHG) emissions to zero, still large number of investments in renewable sources are expected in the whole of Europe. Consequently, an adequate future design of the power market would be one that fosters more operational flexibility to allow TSOs to efficiently manage the increased uncertainty in the system.

On the other hand, the coupling of the regional day-ahead markets brought improvements over market results. Transmission capacity is, since then, used more efficiently and the flow of traded energy is in accordance to the price differences between regions (Borggrefe & Neuhoff, 2011). Market coupling favours convergence of prices, which boosts competition and therefore better quality services and ultimately better prices for consumers. Moreover, (Meeus, et al., 2005) highlighted that a further stage of market integration is necessary and a cross-border balancing and intraday markets should be set up. In fact, according to the European Commission, short-term cross-border markets should be at the core of the European power market redesign. These markets are able to best capture the value of operational flexibility sought for large-scale integration of renewables due to their closeness to real-time operation.

Finally, greater degree of liberalization of energy markets, more cross-border interconnections and larger amounts of renewable technologies in the system require changes to the way the power system is operated. With a top-down framework, the foundations on which the internal electricity market in Europe is being built are laid through the development of the network codes. Elaborated by the European Commission, the ENTSO-E and the Agency for the Cooperation of Energy Regulators (ACER), these codes provide a complete set of rules on different areas of the electricity market that will need to be implemented and complied with across Europe. They will become binding technical EU regulations. When this happens, Europe will then be one step closer to the realisation of the Internal Energy Market (IEM), and hence, of its energy goals.

1.2. Impact of large-scale integration of Renewable Generation

The energy target set for 2020 to reach at least a 20% share of energy coming from renewable sources and the initiative of decarbonising the electricity sector by 2050 will lead to a significant increase in green energy technologies in the power system. Almost 50% of this installed capacity will be represented by wind and solar power plants which are, of all renewable energy sources, the most intermittent, unpredictable and unevenly distributed sources around the continent (Eurelectric, 2010). The large-scale introduction of these types of renewable sources will impact both the functioning of the electricity markets and the operation of the transmission and distribution grids.

The following sections go further into the effects of the expected high integration of renewable energies on the coupled day-ahead, and current intraday and balancing markets in Europe and on the system operation and congestion management in the network.

1.2.1. Effects on the day ahead, intraday & balancing electricity markets

In most Member States there are three distinct types of electricity markets currently in place: day-ahead, intraday and balancing markets. Day-ahead and intraday markets are energy markets in which power is traded on different timeframes, as their names accurately suggest, while balancing markets have been traditionally used by system operators to provide reserves and response capacity to balance the system when unplanned events take place, as in the case of plant outages, load prediction errors or wind uncertainty.

After the regional coupling of the North-Western and South-Western day-ahead markets in May 2014, a greater harmonization of the wholesale prices is expected in the whole region. Such convergence of prices was also the initial result after the market coupling in the Central-Western (CWE) region took place in November 2010 (Figure 1.1).

The current market coupling mechanism uses a common price formation that allows to optimize the allocation of cross-border interconnection capacities for power exchange. The allocation of this transmission capacity is done through implicit auctioning. This means that the available transmission capacity is auctioned jointly with the auctions of electricity in the spot markets, accomplishing in this way the integration of the different national electricity markets. The optimized use of the interconnections between countries in theory yields two results: (i) a general decrease in spot prices and (ii) a general decrease in the differences of spot prices between regions provided that the required transmission capacities are in place.

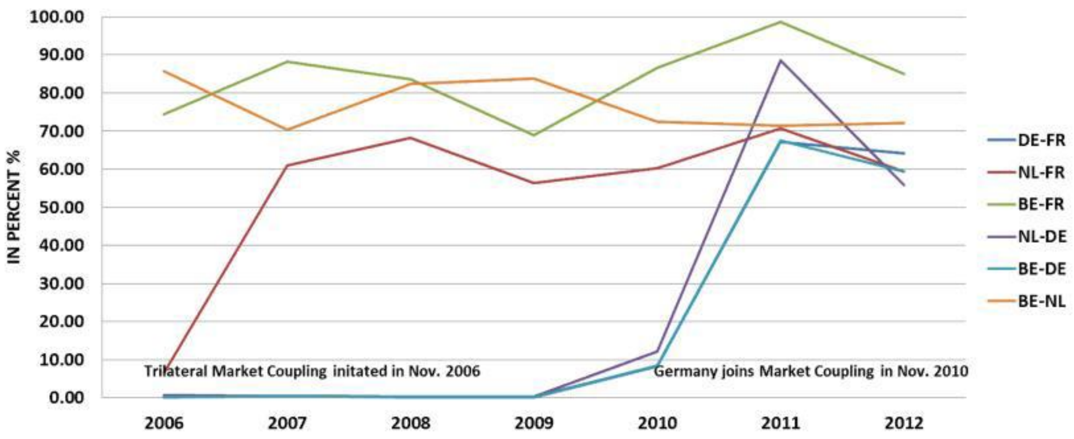

Figure 1.1. Price convergence in Central-Western Europe. Source: (Böckers, et al., 2013).

Firstly, prices should decrease because, given the principle of the merit order dispatch, cheaper power from renewables, for example, can be delivered to other regions that would not have been possible otherwise. It is worth mentioning that the impact of the renewable targets on the day-ahead market cannot be decoupled from an increasing coupling of the regional day-ahead markets since they are part of the same strategy (Eurelectric, 2010). To illustrate the reader, Figure 1.2 presents the power exported from Germany to France and the day-ahead prices in France after the market coupling took place in 2010. In the graph, when German imports increase, French day-ahead prices fall. Knowing that Germany has a higher renewables capacity share compared to France, it is likely that this price drop is due to cheaper power imports than its nuclear power, i.e. renewable sources (Doan, 2012).

Secondly, if there is sufficient cross-border capacity and the day-ahead prices in France fall due to German imports, then spot prices in Germany will increase because there is more power produced with respect to the situation where there are no imports to France. In this way, a price equilibrium is reached and price differences are reduced. However, in practice prices are yet not completely harmonized and price divergence is still significant like in the year 2012 in Figure 1.1. This is due to congestions in the network caused by still insufficient transmission capacity in that region, unexpected failure of generators, sudden increase in demand or too much renewable generation in one country.

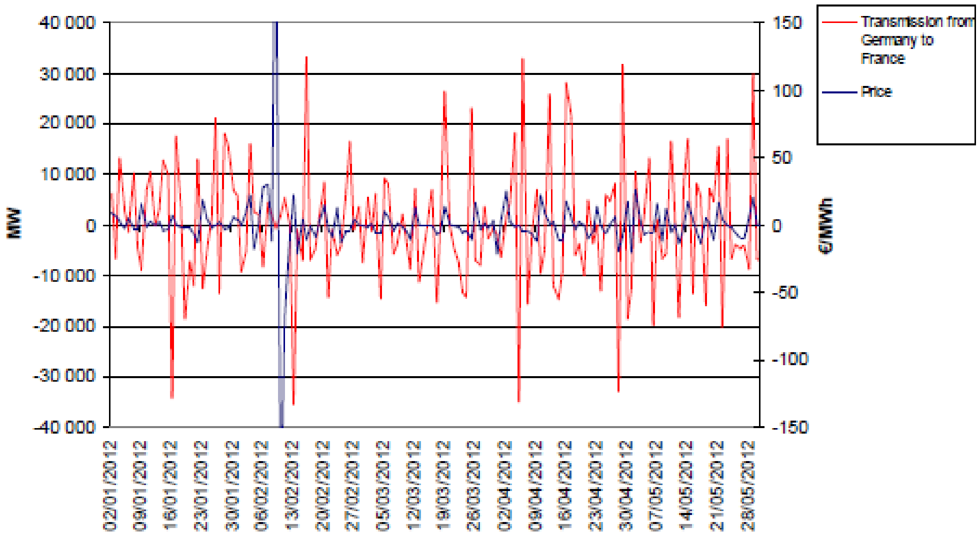

Figure 1.2. Day-ahead prices in France and power transmissions from Germany to France. (Source: RTE, Powernext)

In fact, renewable sources in the system lower day-ahead prices on average. However, due to the stochastic behaviour of weather and therefore the intermittent nature of renewables, uncertainty levels increase and sudden price spikes can appear when there is no wind or sun available. As a result, price volatility increases. Moreover, higher penetration of renewables will increase price volatility even more, influencing the future price hedging strategies and the behaviour of energy traders in the derivatives market. Furthermore, TSOs will have the difficult task to decide in real time the most appropriate capacity to dispatch when suddenly the wind stops or the sun is not available, resulting in higher costs and therefore higher spot prices.

Regarding intraday and balancing markets, several countries in Europe have them in place to allow for readjustments of the dispatch during the day. However, the market setups differ significantly from one country to another and are still far from competitive and efficient harmonized European markets (Figure 1.3) (Borggrefe & Neuhoff, 2011).

The main issue with their current design in most countries is the inability to optimize between the balancing and the day-ahead markets. Energy suppliers have to send their commitment offers to either the day-ahead or intraday markets, or to the balancing market. In many cases it is not possible to change this commitment when we are closer to real-time. Therefore, while already committed power plants in the day-ahead market would be able to provide upward balancing power when they are asked to reduce production due to an increase in wind feed-in, they are unable to do so. Instead, more expensive technologies have to provide the balancing services.

Moreover, the increased uncertainty in day-ahead markets due to the growing penetration of renewables has encouraged an increase in demand for reserve capacities in these markets to ensure security of supply. This results in larger amounts of startups and part-load costs, thereby increasing generation and operational costs of the system (EWIS, 2010). This trend is expected to continue with an increasing share of renewables, and despite the improvements in wind forecasting this will not enable a full use of the system's flexibility if no changes are made in the design of these markets.

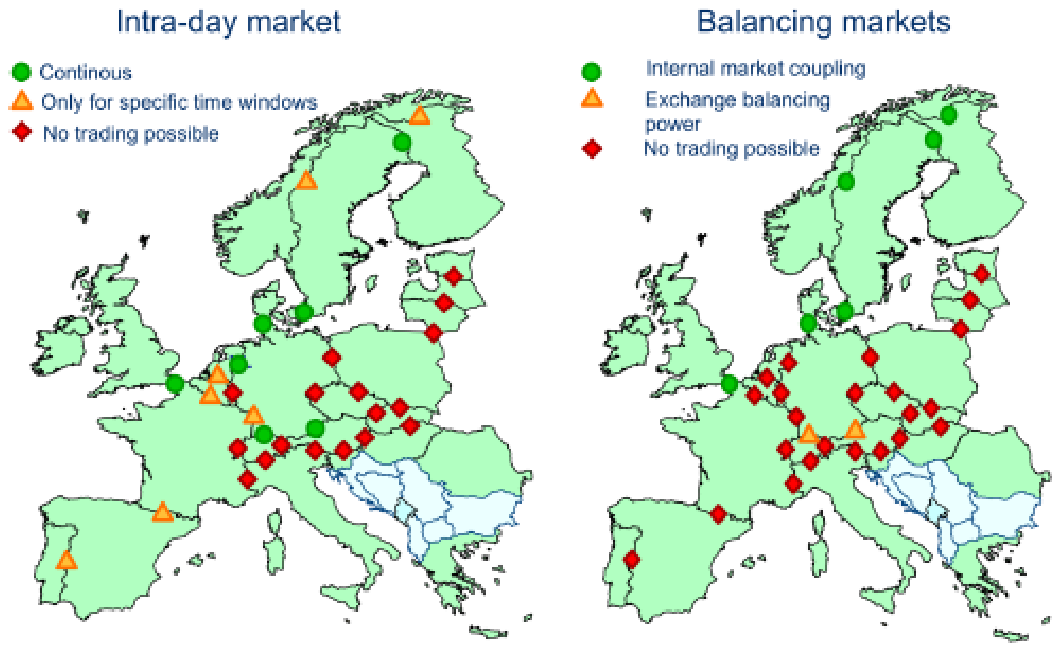

Figure 1.3. Cross-border arrangements in intraday and balancing markets in Europe in 2009. Source: EWI, 2010.

The initiative of regional coupling between the European day-ahead markets now extends to applying such coupling mechanism to both intraday and balancing markets. Until now this had low priority in many countries. (Smeers, 2008) argues that day-ahead, intraday and real-time are different steps of a single trading process and therefore they require a single trading platform, instead of the current three different market schemes. The future market design should allow TSOs to efficiently manage the increased uncertainty in the system and generators should help by allowing them to offer a joint bid for energy production and provision of balancing services.

The main beneficiaries of the reviewed market design would be European consumers who benefit from improved security of supply and lower system costs, which results in lower electricity prices. System operators also benefit from more transparent operational procedures and reduced costs. However, the improvement and harmonization of the electricity markets can be seen as a threat to dominant generation companies who might see their large benefits shrink due to an easier entry of competing generators in the intraday and balancing markets (Borggrefe & Neuhoff, 2011).

1.2.2. Effects on congestion management

Congestion management has become an operational challenge in more and more liberalized power systems due to the increasing number of bilateral contracts for electricity trade. Transmission congestion is the operating condition in which there is insufficient transmission capacity to deliver all the traded energy simultaneously and therefore certain lines in the network may become overloaded. TSOs, as operators of the system, are in charge of alleviating these situations and restoring a secure state of the system.

The further deployment of renewable energies in the following years is expected to take place mainly in offshore sites, away from load centers, thus new transmission lines will be required. Besides, distribution grids will also need new investments due to a large increase of distributed generation.

In the case that the large introduction of renewables is not accompanied by a timely delivery of the required transmission investments, as already mentioned in section 1.1, transmission constraints would appear affecting system operation. Congestion already exists in European cross-border interconnections, but the expected renewable penetration will change this cross-border congestion profiles to a greater extent (Neuhoff, et al., 2011).

Currently, the most typical way TSOs solve congestions in the European network is by redispatching generation, curtailing demand or a combination of both. The main concerns of the system redispatch solution are its high costs, which are usually and ultimately paid by the consumers, and its susceptibility to high levels of market power. Also, even if generators are allocated with the redispatch costs, incentives to locate outside congested areas would be relatively low, resulting in a long-term economically inefficient solution to congestion (Hakvoort, et al., 2009).

Therefore, an adequate congestion management mechanism should be able to promote the efficient use of the existing transmission capacity while maintaining a reliable and secure power system, and guaranteeing maximum transparency to public and private investment agents.

According to (Neuhoff, et al., 2011) an effective congestion management scheme for Europe would have to integrate the following criteria:

- An integrated approach of national and international congestion management
- Joint allocation of international transmission rights
- Integration of congestion management with day-ahead energy markets
- Integration of congestion management with intraday and balancing markets
- A transparent approach to facilitate secure and effective cooperation and information exchange among European system operators

1.3. Power market designs and congestion management

In previous sections it has been illustrated the improvements, the future challenges and the importance of a closely integrated operation of the power system to achieve a secure, competitive and sustainable European electricity system. The network codes, developed by the European Commission, the ENTSO-E and ACER, set the rules and procedures to trade electricity across Europe based on some framework guidelines and hence define the new power market design. The power market design proposed by European stakeholders is, as briefly mentioned in section 1.1, based on implicit auctioning and flow-based capacity allocation.

Currently in Europe, the market design is based on a multi-region day-ahead market coupling mechanism, or also known as zonal market. The zonal market approach assumes one electricity price per market zone. In continental Europe every market zone is limited by national boundaries and in the Nordic region every country is divided into several market zones. By doing this, intra-zonal congestion is not accounted for through the market. Instead, only cross-border interconnections are considered and the TSOs manage congestion inside the zones after market clearance, through a redispatch process, incurring in operational inefficiencies as already explained. Now, the allocation method of cross-border transmission capacity is not straightforward mainly because commercial energy flows do not correspond with the actual energy flows in the network. The latter follow Kirchhoff's circuit laws. There are different capacity allocation methods used in worldwide electricity markets, namely the Available Transfer Capacity (ATC) method, the Flow-Based Market Coupling (FBMC) method, both for the zonal market approach, and the nodal market.

Since May 2015, the FBMC model is currently implemented in the day-ahead market of Central Western Europe (Belgium, the Netherlands, France, Germany and Austria). In the rest of continental Europe transmission capacity is still allocated through the ATC methodology. The difference between these two cross-border capacity allocation methods is at what point in time the allocation of capacity is done. In the FBMC method the allocation is partly done with the clearing of the market while in ATC it is done ex-ante. As a result, given the heuristic approach with which the ATC is calculated and the independence of each cross-border link in the calculation, the ATC value is conservative to prevent line overloadings, thus reducing the capacity available to the market (Van den Bergh, et al., 2015). On the other hand, because the FBMC considers the critical lines in the grid simultaneously with the market, the allowed commercial capacity between zones is no longer independent from one another and the final value is less conservative. FBMC method results in a more efficient design for capacity allocation than the previous ATC method. (Smeers, 2008) points out that the FBMC methodology is a reliable allocation method and applicable, from a computational perspective, for all markets from day-ahead to real-time. Despite the improvement in efficiency, the complex calculations that entail the FBMC method questions its transparency towards market players.

Even though the third allocation method, the nodal market, is not viewed among the targets of the Internal Electricity Market model, according to (Neuhoff, et al., 2011) it offers an even more efficient and transparent approach to congestion management. In many power systems in the US (ERCOT, CAISO, ISO-NE, NYISO, and PJM markets), this option was chosen over zonal market due to the changing nature of the congested lines in their highly-meshed networks. This method takes into account all physical transmission constraints in the market clearing, therefore every node in the network represents one market zone, i.e. one price. Nodal market scheme is also known as Locational Marginal Pricing (LMP). The price in every node reflects the locational value of energy, it includes the cost of supplying the energy as well as the cost of delivering it. Price differences in nodes show the costs of transmission at the same time it gives proper allocation signals to market players on where to site required generation, transmission and load. Moreover, since there is no need for a redispatch phase after market clearance, gaming opportunities and abuse of market power would be significantly reduced. Equally important, the link between the day-ahead market and the intraday and balancing markets would be improved (Borggrefe & Neuhoff, 2011).

(Neuhoff, et al., 2011) describe the potential benefits that this market design would add to the European context given the change in the generation portfolio and the need for a more efficient use of transmission capacity. Regarding this, it could be useful to rethink in a new zone configuration for Europe. They argue that the costs of changing the power market design and establishing new trading arrangements can be high but in case of implementing the change the sooner it is done the cheaper it would be. Nevertheless, some incumbent generation companies might be opposed to the change because of rent re-allocation issues. Consumers would be the great beneficiaries due to lower system costs that would translate into lower electricity prices. Nevertheless, more initiative at a European level and a committed high-level support among Member States would be essential for further steps.

1.4. Problem definition

Renewable energy technologies are becoming an increasingly important source of electricity production in Europe's power system, which is making an important effort to move towards a decarbonized, secure and more affordable system.

Alongside the benefits brought by the introduction of more green technologies, the uncertain nature of these sources impact the functioning of the markets and the operation of the system in all time scopes. In relation to this research, the daily variability of wind and sun influences the unit scheduling in the day-ahead markets, in which flexible and commonly more expensive units need to be available. Moreover, the limited predictability of wind generation or the uncertainty degree in the forecasted errors calls for the need of a dynamic balancing mechanism that is able to accomplish the required adjustments in real-time operation. Evidently, a significantly larger share of renewables in the power system magnifies these challenges even more. If the current electricity trading arrangements are maintained, TSOs would have to face many more difficulties, incurring in even more inefficiencies.

From a network topology perspective, the integration of renewable sources is not evenly distributed around the continent. While wind farms are mostly concentrated, and are expected to further expand, in regions close to the North Sea, photovoltaic solar panels are located in specific and sunnier areas of the continent. This uneven distribution of generation sources, if not accompanied by a proper transmission network expansion plan, can lead to significant modifications in the power flows through the grid, affecting in turn the current cross-border congestion profiles between countries and underutilizing the available network capacity. An effective congestion management approach that captures the future elements of the system and addresses the foreseen challenges would contribute to maximizing the benefits of power trade in Europe.

A long-term solution to the above challenges is closely linked to reviewing the current power market design and how it manages congestion in the electricity grid. Attention should be focused on whether it makes more economic and operational sense to enhance, from a bottom-up approach, the current European model with additional features focused on capacity adequacy and the expected flexibility needs or implement a new market design with top-down support. With this approach, this thesis performs a comparative study of the two different power markets discussed above: the zonal market with the FBMC capacity allocation method and the nodal market.

1.5. Research objectives

Following the research problem above, the question hence arises by how much can the power market design structure and its market features affect the provision of cost-efficient electricity in high renewable scenarios, and, consequently, how the market participants on a European scale are influenced by it. The research objective of this thesis can be thus formulated as *gaining a better understanding of the European power market in presence of large amounts of renewable energy sources and under different power market designs.*

The research objective prompts the following main research question:

To what extent can the power market design and the future expected large-scale integration of renewable energy sources have an effect on the system's variable generation costs of electricity?

Additionally, several subquestions are formulated that provide an answer to how the main question can best be explained; to identify what is the cause of such effect, if any; and to why it is of importance to address this research's main question, respectively. The subquestions are formulated as follows:

1. How can the European power system be modeled to best reproduce its behaviour when functioning under different power market designs in combination with high and low renewable scenarios?

2. To what extent the difference in variable electricity generation costs between scenarios and across power market designs can be attributed to an increased usage of renewable technologies, network congestions or non-served energy costs?

3. How can the difference in electricity prices within and between European countries impact the markets' participants behaviour in the power market?

1.6. Thesis outline and structure

This thesis covers the research objective and research questions with the following structure:

Chapter 2 presents the necessary theory of unit commitment models used in the planning and operation of electric power systems as well as the technical and mathematical theory needed to understand the use of optimal DC power flow models. Furthermore, the modeling objectives, the network topology and the modeling methodology to implement the proposed power market designs are addressed. Finally, the mathematical formulation of the specific model used is provided.

Chapter 3 describes the renewable scenarios used based on the Adequacy Forecast & Scenario Outlook of 2014 from the ENTSO-E, which extend to the year 2030, and the necessary input model data and parameter assumptions made. Moreover, a section in this chapter is dedicated to validating the output of the model with reality.

In chapter 4 the research outputs are presented and the answers to the research questions are exposed. Here, the effect on the variable electricity generation costs of the power market design in combination with a high penetration of green technologies is analyzed. Also, further analysis is made on the possible cause or causes that generate the different outputs as well as the degree and the possible implications that these outputs would have on the European energy multi-actor context.

Chapter 5 exposes the conclusions, recommendations and some reflections. Here, the answer to the research questions are formulated and the aim is to connect the results obtained with the model to the current and foreseen situation in the European power system.

Some scope limitations of the thesis are explained in the following points:

- A mathematical optimization model is used to model the short-term planning and operation of the power system. Investments in new generation assets or network capacities are not accounted for.
- Rational, cost-minimizing agents are assumed and strategic bidding of market agents is not taken into account. The optimization problem is solved from a central planner perspective.

- The optimization problem is modeled with deterministic renewable scenarios that are based on the scenario data provided by the ENTSO-E.
- Renewable generation of wind and solar assigned to every specific node of the network is calculated based on the forecasted wind speed and solar radiation time-series in the assumed location of that node rather than on the average of a region covered by that node.
- The flexibility of the power system has been limited by the arbitrary number of thermal units assigned to every node of the network. This has a direct effect on the actual commitment, startup and shutdown schedules. As an example, it is not the same having one thermal unit of a maximum capacity of 500 MW than having two thermal units of maximum capacity of 250 MW each. The flexibility degree with which the power system can operate has been modified.
- Hydro energy resources are left out of the scope in the generation mix in all scenarios. In order to account for this shortcoming, demand values obtained from the ENTSO-E database are adjusted in those countries where hydro accounts for a significant share in the generation mix. The outputs obtained from the optimization model should therefore be interpreted knowing that optimization of hydro resources in combination with intermittent renewable sources will play an important role in the replacement of expensive thermal generation thanks to their flexibility and complementary use.

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CHAPTER 2

THEORY AND MODEL DESCRIPTION

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2. Theory and Model Description

Chapter 2 presents the fundamental concepts in the theory of power systems and the modeling optimization techniques and formulations used in the field. Once these concepts and formulations are addressed, the second part of the chapter describes the modeling approach, the methodology and the formulation chosen for the defined problem.

2.1. Theory of Unit Commitment

Unit commitment models are needed by system operators to schedule efficiently the resources available in order to achieve a reliable and economically sustainable operation of the power system. Unit commitment in power systems is an optimization problem that has the main objective of finding the minimum-cost scheduling of all the generating units in the system over a specified period of time, usually over a short-term horizon. Simultaneously, this objective is subject to meeting the system electricity demand, complying with different types of system constraints (technical, operational, environmental, regulatory), and take into account the long-term signals such as the water value in hydro energy sources and guarantee an appropriate level of reliability.

The unit commitment problem has technical and operational constraints for every generating unit as well as for the coupling operation of these units, and the shorter the temporal scope of the model and the time interval used, the more detailed the modeling of the generating units should be. In general terms, the main constraints that can be found in a common formulation of the unit commitment problem are related to:

- The minimum uptime and downtime of the units
- The upward and downward ramp limits
- The capacity limits of the units
- The status of the units and
- The reserves constraints.

The unit commitment problem, of combinatorial nature, represents a challenging but necessary task for system operators in the daily planning of power systems. An unplanned management of the available generation resources can cause system operators and generation companies to incur in extremely high economic losses. A unit commitment model provides a plan of the physical operation of the system: start-up and shut-down decisions are made and an hourly schedule of the generation park is obtained. Moreover, this short-term planning also helps to forecast the following:

- The operational costs of the system
- The generation costs
- The fuel consumption
- The management of the reservoirs

- The utilization factors for each generation unit
- The aggregated generation for each type of technology and
- The marginal costs of the units.

There exist many different approaches and ongoing research in the literature on how to solve the unit commitment problem. Several numerical optimization techniques have been used to address the problem. These techniques include priority list methods (Sheble, 1990) (Dillon, et al., 1978), dynamic programming (Ouyang & Shahidehpour, 1991) (Muckstadt & Wilson, 1968), integer programming (Garver, 1963) (Snyder, et al., 1987), mixed-integer linear programming (Cohen & Yoshimura, 1983), branch-and-bound methods (Sandrin & Merlin, 1983), and Lagrangian relaxation methods (Shahidehpour & Ouyang, 1992). Priority lists is a quick method that specifies the order in which units are switched on or off, however, the quality of the output is not always assured. Regarding the dynamic programming technique, the precise solution of the model can be obtained but the large computation time is the main disadvantage. Integer and mixed-integer methods apply linear programming by relaxing its integrality requirements but have been used only in small unit commitment problems. The branch-and-bound method is different from other techniques since it assumes no priority ordering, it applies a linear function to represent fuel consumption and time-dependent start-up costs and it calculates the required upper and lower bounds. Finally, the Lagrangian relaxation technique can give a fast solution but it might not always numerically converge providing a low quality solution.

Among the techniques briefly mentioned above, the Lagrangian relaxation and mixed-integer linear programming (MILP) are the most popular methods. According to (Morales-España, et al., 2013), the world's largest competitive wholesale market, PJM, recently switched from using Lagrangian relaxation to MILP. However, despite the many improvements made in MILP solvers, the time needed to solve unit commitment problems continues to be a main limitation. Therefore, a thoroughly improved MILP formulation can really make a difference in lowering the computational overload and making it possible to run larger or more complex problems. Reference to the formulation used in (Morales-España, et al., 2013) shall be made in following sections.

On the other hand, a pure unit commitment model does not include the transmission network, instead the model's approach is to consider that all generation and load is connected in one single node. However, because generation units are scattered in different places interconnected between them across the network, the power flows are restricted to the capacity limits of the transmission lines. Therefore, in order to obtain a feasible commitment schedule of the generators the transmission network should be included in the model: a transmission economic dispatch model is needed.

A transmission constrained economic dispatch problem, namely an optimal AC power flow model, seeks to minimize operational costs of providing electricity by taking into account the network constraints. The model provides as results the power output of each generating unit and the power flows through the transmission lines, as well as a specified operating reserves margin, also known as the spinning reserve. Additionally, the model introduces the important concept of nodal prices or nodal marginal costs which will be addressed in subsequent sections.

Finally, the merger between a pure unit commitment model and a transmission constraint economic dispatch problem provides a full and detailed overview of the required short-term planning carried out by a Transmission System Operator (TSO). However, there are some drawbacks to solving the AC power flow problem. An electricity network with N nodes results in an AC power flow with 2N non-linear equations that are solved iteratively for every time step (Van den Bergh, et al., 2014). Given the non-linearity of the transmission constraints and the heavy computational effort required, a simplified version of an AC power flow based on linear programming is used in practice. Section 2.2 presents the simplifications made for the AC power flow model.

2.2. Theory of Optimal DC Power Flow

In the following section a detailed description of DC power flows is given. The AC load flow constraints can be formulated as linear constraints based on three main assumptions.

1. The inductive component of the AC transmission line is greater than the resistive one for all lines ($R_{ij} \ll X_{ij}$) which means that network losses can be ignored and the line admittances can be simplified to line susceptances in the admittance matrix ($Y_{ij} \approx B_{ij}$). The higher the voltage of the network in question, the more valid this assumption will be.

2. All the bus voltages have a similar magnitude in per unit values. This is achieved by managing the reactive power in the system to maintain voltage fluctuations to the smallest possible degree. However, real life examples show that this assumption is the largest source of DC power flow errors.

$$|V_k| \approx 1\ p.u. \qquad \text{(Eq. 2.1)}$$

3. The phase angle differences between neighbouring node voltages (i and j) under stable operation conditions are small. This translates into a linearization of the sine and cosine terms in the AC power flow equations as equation 2.2 shows. In general terms, this linearization is more correct in weakly loaded grids, but even in peak load instances, the error made by this assumption is less than 1%.

$$\sin(\delta_i - \delta_j) \approx \delta_i - \delta_j$$
$$\cos(\delta_i - \delta_j) \approx 1 \qquad \text{(Eq. 2.2)}$$

How close reality adjusts to these three assumptions is what makes the solution given by the DC power flow model more accurate. Generally, compared to AC power flows, the accuracy of DC power flow models when applied to high voltage grids is close to 5% when averaged over all lines. Therefore, by keeping in mind the conclusions drawn for individual lines, the error deviations are assumed to be acceptable.

Although a reference bus is needed as reference point in the linearization of the power flow model, the literature (Sheble, 1990) (Baldick, 2003) (Dillon, et al., 1978) (Baldick, et al., 2005) proves that the DC power flow formulation is not significantly sensitive to different operating points. Therefore, as long as the network topology is kept unchanged, the DC power flow equations can be used for all operating points indistinctly.

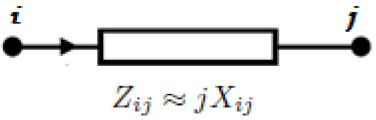

Figure 2.1. Impedance of line ij

In the DC power flow problem perfect voltage support, reactive power management, negligible network losses are assumed and only line active power flows are considered. The active power flow through an AC transmission line follows the following equation:

$$p_{ij,AC} = \frac{|V_i|\,|V_j|}{X_{ij}} \sin(\delta_i - \delta_j) \qquad \text{(Eq. 2.3)}$$

By applying the mentioned assumptions above, equation 2.3 simplifies to the DC power flow equation, Eq. 2.4:

$$p_{ij,AC} = B_{ij}\,(\delta_i - \delta_j) \qquad \text{(Eq. 2.4)}$$

Similarly, the simplified DC power flow equation for nodal active power balances in one node is shown below (Eq. 2.5), with p_{ij} being the positive direction of the active power flow from node i to j and B_{ij} the susceptance of line ij between node i and j (Van den Bergh, et al., 2014):

$$p_i = \sum_j B_{ij}(\delta_i - \delta_j) \qquad \text{(Eq. 2.5)}$$

If node $i = 1$ is now considered to be the reference bus, Eq. 2.5 can be then written in matricial form:

$$\begin{bmatrix} p_2 \\ \vdots \\ p_i \\ \vdots \\ p_N \end{bmatrix} = \begin{bmatrix} B_{22} = \sum_j B_{2j} & \cdots & -B_{2i} & \cdots & -B_{2N} \\ \vdots & \ddots & \vdots & \ddots & \vdots \\ -B_{2i} & \cdots & B_{ii} = \sum_j B_{ji} & \cdots & -B_{jN} \\ \vdots & \ddots & \vdots & \ddots & \vdots \\ -B_{2N} & \cdots & -B_{Ni} & \cdots & B_{NN} = \sum_j B_{Nj} \end{bmatrix} \cdot \begin{bmatrix} \delta_2 \\ \vdots \\ \delta_i \\ \vdots \\ \delta_N \end{bmatrix} \qquad \text{(Eq. 2.6)}$$

$$\delta = \frac{\boldsymbol{P}}{\boldsymbol{B}} = \boldsymbol{Z} \cdot \boldsymbol{P} \qquad \text{(Eq. 2.7)}$$

Therefore, the voltage phase angle δ_i is calculated as in Eq. 2.8 and, by substituting this expression in Eq. 2.4, the Power Transfer Distribution Factors (PTDFs) are obtained, as shown in Eq. 2.10.

$$\forall\, k = 2, \dots K \qquad \delta_i = \sum_{k=2}^{K} Z_{ik} \cdot p_k \qquad \text{(Eq. 2.8)}$$

$$p_{ij,AC} = B_{ij} \left(\sum_{k=2}^{K} Z_{ik} \cdot p_k - \sum_{k=2}^{K} Z_{jk} \cdot p_k \right) = \sum_{k=2}^{K} B_{ij} \left(Z_{ik} - Z_{jk} \right) p_k \qquad \text{(Eq. 2.9)}$$

$$p_{ij,AC} = \sum_{k=2}^{K} PTDF_{ij,k} \cdot p_k \qquad \text{(Eq. 2.10)}$$

Finally, the DC power flow equations of the AC transmission lines in the network are represented in matrix form in Eq. 2.11.

$$\boldsymbol{P_{ij,AC}} = \boldsymbol{PTDF_{ij,i}} \cdot \boldsymbol{P_i} \qquad \text{(Eq. 2.11)}$$

The Power Transfer Distribution Factors (PTDFs) linearly relate the power injections in the nodes of the network (p_i) and the active power flows in the lines ($p_{ij,AC}$). In essence, the link between p_i and $p_{ij,AC}$ is a relation between reactances. Also called sensitivity factors, an element in the PTDF matrix provides an approximation of how the power flow through transmission line ij changes with an injection or withdrawal of one MW of active power at node i (Van den Bergh, et al., 2014). For the PTDF calculation, the reference node or slack bus needs to be removed from the DC power flow equations in order to obtain a set of linearly independent equations.

Finally, the active power flows are bounded by the capacities of the transmission lines, Eq. 2.12.

$$p_{ij,AC\,min} \leq p_{ij,AC} \leq \; p_{ij,AC\,max} \qquad \text{(Eq. 2.12)}$$

Until this point, only AC transmission lines have been considered in the formulation. However, High Voltage Direct Current (HVDC) lines can also be part of the meshed high voltage grid. In case the HVDC line is embedded within an AC grid, the power flow through this line can be fully controlled. If the HVDC line connects extremes of the network, like for example offshore wind farms with the continental grid or interconnects two asynchronous power systems, then the HVDC transmission line is not a true power flow controlling device.

Van den Bergh (2014) proposes a methodology to model these lines based on the replacement of the line capacity for a combination of a positive and negative power injections at the two nodes that connect the HVDC line. The methodology applied in this research uses Van den Bergh's idea of replacing the power flow through the HVDC line ($p_{l,DC}$) for the nodal injections in the corresponding nodes ($p_{i,DC}$) through the relationship given by $\boldsymbol{A_{DC}}$, the incidence matrix of the HVDC network. $\boldsymbol{A_{DC}}$ is a L×N matrix with $a_{l,n} = 1$ if line L starts at node N, $a_{l,n} = -1$ if line L ends at node N and $a_{l,n} = 0$ if line L is not incident to node N. Therefore, $p_{i,DC}$ represents a vector that contains the nodal injections in every node i due to the power flow through the HVDC lines l (Eq. 2.13).

$$\boldsymbol{P_{i,DC}} = \; \boldsymbol{A_{DC}}^{\boldsymbol{T}} \cdot \boldsymbol{P_{l,DC}} \qquad \text{(Eq. 2.13)}$$

Even though no reactance is associated to the HVDC lines, the DC power flow equations of the AC lines should also include the effect of the power flows in the HVDC lines. This effect is included in Eq. 2.14 by adding the term $p_{i,DC}$ to Eq. 2.11. Finally, Eq. 2.14 are the DC power flow equations of the AC transmission lines in a network with HVDC lines.

$$\boldsymbol{P_{ij,AC} = PTDF_{ij,i} \cdot (P_i + P_{i,DC})} \qquad \text{(Eq. 2.14)}$$

Equation 2.14 implicitly takes care of the power balance in the nodes that are connected to at least one AC transmission line. However, an additional constraint needs to be added in order to guarantee power balance in the nodes connected only to HVDC lines (Eq. 2.15). This constraint includes the net injection calculated as a result of the net generation, demand and energy not served in every node i (${p_{i,DC}}^{Net}$) plus the net inflow due to the power flow of HVDC lines connected to node i.

$$\boldsymbol{{P_{i,DC}}^{Net} + {A_{DC}}^{T} \cdot P_{l,DC} = 0} \qquad \text{(Eq. 2.15)}$$

2.3. Locational Marginal Prices

The Locational Marginal Prices (LMP), or nodal prices, are also the marginal costs of electricity. Nodal prices guarantee at every point in time that demand is met at minimum cost and price differences reflect generation and transmission capacity scarcity, as already explained in section 1.3. The LMP mechanism takes into account all the physical transmission constraints in the clearing of the day-ahead market. Based on a real representation of the network and a transparent approach, the price calculation is done *a posteriori*, after solving the linear programming model, and is based on the dual variables of the system balance and network constraints.

Every constraint in the model has a corresponding dual variable, also called shadow price. A dual variable provides crucial information about the system. It measures how much the objective function varies when the corresponding constraint is incremented by one unit. In other words, in this case they measure the change in total variable generation costs when demand, generation or non-served energy vary by one unit.

It should be noted that non-binding constraints correspond to shadow prices equal to zero. In the event that some constraints are binding, for example a specific line is operating at its limit capacity, the shadow price for that line will be non-zero and thus it indicates the presence of transmission congestion in the network. The system balance constraint, specified as an equality constraint (Eq. 2.16), always binds; it suggests a price that always supports balance in the system.

$$\forall\, p \in P \qquad \sum_{g \,\in\, ig_{i,g}} p_{g,p} + \sum_{i \,\in\, I} \left[ig_{i,p} + nse_{i,p} \right] = \sum_{i \,\in\, I} D_{p,i} \qquad , \lambda_{i,p}$$

Eq. 2.16. System balance constraint and its dual variable.

The following fundamental formula, in the absence of network losses, is used to calculate the LMP in any node:

$$\forall\, i \in I, \forall\, p \in P \qquad LMP_{i,p} = \lambda_p + \sum_{ij_{AC}} PTDF_{ij,c,i} \cdot \mu_{ij,p} + \beta_{i,p}$$

Eq. 2.17. Formula of locational marginal prices (€/MWh) based on dual variables.

where:
i − Node
p − Hourly period
λ − Shadow price (dual variable) of the system balance constraint
ij_{AC} − AC power transmission line
$PTDF_{ij,c,i}$ – Power Transfer Distribution Factor of AC transmission line ij due to node i
μ − Shadow price (dual variable) of the network constraint of AC transmission line ij
β− Shadow price (dual variable) of the power balance constraint in nodes with only HVDC lines

The advantage of using a nodal pricing mechanism over a FBMC or ATC mechanism is that it efficiently manages congestion in the network without interference of the TSOs. This is because they internalize the energy losses and congestions in accordance with the network constraints. As an important result, nodal prices give efficient economic short-term signals to market participants and stimulate the required investments and the appropriate performances of system operation.

2.4. Modeling approach

Large-scale integration of renewable energy sources in the near future is expected to become a main driver to enhance operational practices to provide a more flexible and efficient functioning of the European power system. This flexibility can be achieved from the generation side, from both conventional and renewable generation, by improving their system reliability and stability capabilities; it can also be achieved from the load side, with demand response and also from the operational side, by better exploiting the existing transmission infrastructure and by sharing greater cooperation between regions for transmission expansion.

Moreover, the power market design, which in general terms dictates the rules of the power system's functioning, has an impact on how the power system's flexibility is managed and therefore it also has an effect on the variable generation costs of the power system. In order to stress the relevance of the power market design in presence of increasing renewable capacity, an energy model is developed. The following subsections elaborate on the modeling objectives, the type of the chosen model and its scope and the modeling methodology used to implement the proposed power market designs.

2.4.1 Modeling Objectives

The interest of this research lies in gaining further insights on the functioning of the European power system under different power market designs taking into account the large amounts of renewable sources that will be integrated in the following years. Up until now system operators have had relatively little problems integrating small amounts of RES. However, according to the European Commission, a new renewable energy target has been set: at least 27% of the final energy consumption in the European Union as a whole should come from renewable sources by the year 2030. This is expected to unfold many challenges for TSOs in efficiently managing the network as explained in section 1.2.2.

In order to reflect the impacts of the high RES integration in the functioning of the power system, a bottom-up model approach is chosen. With this approach the considered energy system is technically and economically parameterized and looked at from a technological perspective. Following this, a comprehensive analysis of the technological aspect under study is allowed (Jägemann, et al., 2013), in this case the large deployment of RES technologies in the power system under different power market designs.

Within this bottom-up approach, an optimization model is selected over a simulation model, like agent-based models or system dynamics models. TSOs are the entities that operate and manage the power system, and their aim is to manage it in the least costly way possible. Hence, the ability of the optimization model to determine a system optimal solution from a centralized perspective makes it more suitable for the present research.

The aim is to analyze the impact of the power market design on the power system's variables, like total variable generation costs, hourly electricity prices, hourly line congestions, RES curtailment and total production derived from different fuel types, while subjected to several scenarios of increasing degree of RES integration. Therefore, it is preferred to develop a model that gives the optimal functioning of the system for a given objective function, i.e. minimization of total variable generation costs, and a set of constraints that express the technical limitations and political targets in the system.

2.4.2 Modeling the Day-Ahead Market

With the theory of unit commitment and optimal DC power flow models explained in sections 2.1 and 2.2, the optimization model developed in this research solves the unit commitment problem and a transmission constrained economic dispatch of the units for a conceptual network of North-West and central Europe. Figure 2.2 shows a representation of the modeled network.

The model simulates the day-ahead market for the European network in Figure 2.2 from a centralized decision making point of view. This means no strategic behaviour between agents is considered in the model. The day-ahead market is solved by minimizing total variable generation costs at the same time it allocates the hourly demand over the existing generating units and complies with the technical limitations of the power system, i.e. maximum capacities of the generators or transmission line limits.

Morales-España et al. (2013) proposes a mixed-integer linear programming (MILP) formulation of the unit commitment problem. Compared to other existing and efficient formulations, this tighter and more compact formulation reduces the feasible region that needs to be explored by the solver and it increases the speed with which solvers search the optimal integer solution in that feasible region. This model's formulation characteristics lower the model's computational complexity in comparison to other unit commitment formulations, making it attractive for large unit commitment problems representing large power systems. For this reason, this UC formulation is chosen in this research. For a detailed elaboration on the peculiarities and advantages of the mentioned formulation, the interested reader is referred to Morales-España et al. (2013). Additionally, the network elements have been added to the UC formulation as it will be explained in the mathematical formulation section, section 2.4.

Figure 2.2. Conceptual European network modeled in the day-ahead market

Technological scope

The model includes the operational costs and technical characteristics of 873 conventional power plants as well as their commitment decisions. The following generation technologies are considered:

- Nuclear power plants
- Coal-fired steam power plants powered with coal or anthracite
- Lignite-fired steam power plants
- Heavy and light fuel oil power plants
- Combined cycle gas turbines (CCGT) powered with natural gas
- Gas-fired steam turbines

Regarding renewable technologies, both onshore and off-shore wind and solar energy production are included in the generation mix. Normalized generation profiles of wind and solar energy which account for the characteristic wind and solar daily patterns are included as input data in the model from The National Centers for Environmental Prediction (NCEP) Climate Forecast System (CFS) database (Saha, et al., 2011), and scaled with the renewable installed capacity in every RES scenario considered. The thermal generation mix is also updated with the scenarios, except hydro generation, which given the lack of input data, was not considered.

It should be noted that renewable energy production is given priority in the model as no operational cost is assigned to it and curtailment, this is disconnecting renewable sources from the power grid, is allowed to happen in situations of sudden lack of demand or line congestions.

Temporal scope

The model calculates the optimal economic dispatch schedule that meets the hourly demand for one week in July in a reference scenario in the year 2014. Furthermore, another five scenarios representing different projections of RES integration for the years 2020 and 2030 are used to help assess the system's operation adequacy in these situations. These scenarios are named as scenario EU 2020 and Visions 1, 2, 3 and 4 for the year 2030. A detailed description of these scenarios is done in chapter 3.

Regional scope

Twelve countries in the European Union are covered in the modeled network with one, two and up to five nodes per country, in the case of Germany. In total the model contains 22 nodes connected by a total of 72 transmission corridors. Figure 2.2 shows the network topology with the nodes and transmission lines used. This power system is a highly simplified version of the real high voltage European network. However, the number and type of connections between countries are defined in accordance to reality.

Transmission corridors in the network differ between AC and HVDC lines. Their transmission capacities and number of circuits in each corridor are defined based on (Van Blijswijk, et al., 2015). The HVDC links mainly connect remote regions with renewable resources to load centers in the meshed AC continental power system. Moreover, both types of transmission corridors are modeled differently. As already mentioned in section 2.2, AC transmission lines have an electrical reactance associated to them which largely determines the distribution of the power flows in the grid. On the other hand, the flow through HVDC transmission lines is not dependent on an electrical reactance but still affects the flows in the rest of AC transmission lines in the network. The specific network formulation will be detailed in section 2.5.

Regarding the allocation of thermal generation in the grid, a generation database from TU Delft (Enipedia) was initially used as an indication of the number of existing units and their location in every country. However, given the incompleteness of the data, an arbitrary estimation of the number of generating units in every node and for every type of technology was made. This estimation was calculated by taking into account the country's generation mix for the scenario in question and assuming a range of realistic capacity values of the generators according to the fuel type. No change in the number of units is assumed across scenarios, only the capacities of these units change in order to adjust to the new generation mix in the different scenarios. Tables D.6 to D.11 in Appendix D show the capacity values used according to the fuel type and the scenario.

With respect to renewable generation, the normalized wind and solar feed-in profiles implicitly account for regional variations of wind speed and solar radiation throughout the power system.

Regarding demand, the national hourly demand value obtained from the online Transparency Platform of the ENTSO-E is allocated to every node in the country proportionally to the population in every zone covered by every node. National population statistics from the year 2013 are mostly used. In this way, every hour and every node in the network have one demand value assigned.

2.4.3 Model Implementation of Power Market Designs

In this section the methodology used to model the different power market designs discussed in section 1.3, the FBMC allocation method for the zonal market and the nodal market, is presented. They are modeled according to how congestion is managed in each case. Figure 2.3 shows a schematic representation of the modeling process described below.

In the nodal market, as previously explained congestion is entirely handled through the market. In this case the unit commitment and economic dispatch model is run with all the network constraints activated. The output dispatch of the model is therefore feasible with all the constraints and needs no adjustments.

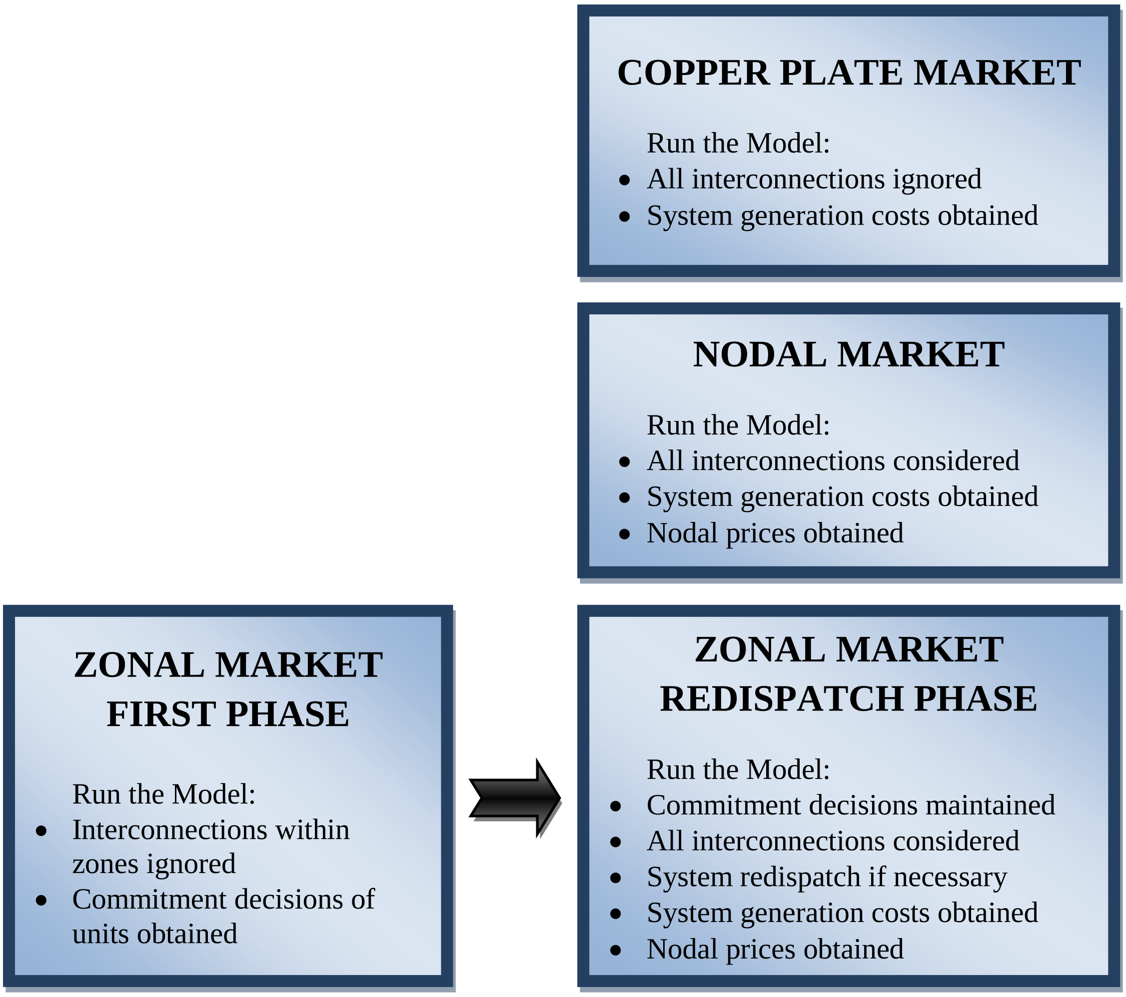

Figure 2.3. Schematic representation of the modeling process of the power market designs

A zonal market with a Flow Based Market Coupling (FBMC) capacity allocation mechanism is modeled in two different steps. In a first phase the unit commitment schedule of the generating units and the economic dispatch is calculated by the TSO once the clearance of the market is done. In the model this is done by running the optimization algorithm taking into account only cross-border interconnections. The national transmission lines are ignored by setting their inductive reactances to zero and their capacities to a very large value.

During the second phase, the TSO evaluates intra-zonal congestion within national boundaries, and checks the feasibility of the dispatch outcome with the national transmission constraints. In practice, this translates into running the MIP economic dispatch model once again taking into account all the transmission lines. In the redispatch phase the commitment, startup and shutdown schedules obtained from the economic dispatch in the first phase are fixed; no startup or shutdown of plants can now take place. The redispatching process should be facilitated by those units who are already committed.

Moreover, given the direction towards where Europe is heading, a reference model is used for comparison purposes. This model, referred to hereafter as Copper Plate, assumes a perfectly future integrated Internal Electricity Market with the sufficient network capacity in all locations that ensures a single wholesale price and prevents any congestion from existing in the whole of Europe. In practice, this major assumption translates into running the unit commitment and economic dispatch model without taking into account the transmission constraints of the European network. Knowing that the current situation is far from such ideal model, it serves as a reference with respect to the zonal and nodal markets and it provides with a rough estimation of the studied parameters in a yet unreal electricity system.

2.5. The Optimization Problem. Model Formulation

The clearance of the day-ahead market is modeled with a unit commitment and a transmission constrained economic dispatch model (UC & TCED). The optimization model minimizes the total variable generation costs of the considered power system (Morales-España, et al., 2013). These costs include fixed generation costs comprised by the fixed fuel consumption costs and the startup and shutdown costs, and the operational costs that include the variable production of the units and the CO_2 emission costs.

Simultaneously, the optimization problem is constrained to a set of technical limitations of the thermal units, to maximum wind and solar hourly generation profiles and to line transmission capacities, among the most relevant ones.

The optimization problem is programmed using GAMS (General Algebraic Modeling System), a high-level modeling software for mathematical programming and optimization. By using the GAMS solver, Cplex, large linear and mixed integer programming problems can be solved. The GAMS code of the model can be found in Appendix A. An interface with Excel-GAMS-Matlab was prepared to input the data into the software and generate the output figures.

The mathematical formulation implemented in the model will be presented and explained in the section below. Given its complexity, a text representation of the model is presented in Text Box 1 to help the reader understand the functioning of the model. The tight and compact formulation used is adapted from (Morales-España, et al., 2013), and additional parameters and variables have been added in order to model the dispatchable HVDC transmission lines existing in the network.

The code in GAMS is divided mainly into four differentiated sections: sets, parameters, variables and equations. In the following section the equations will be presented and explained. Refer to the Nomenclature for a clarification of the defined sets and parameters used in the model. For consistency reasons, uppercase letters denote parameters and sets. Lowercase letters denote variables and indexes.

Text Box 1. Text scheme of optimization model

Optimization Problem: Unit Commitment & Transmission Constrained Economic Dispatch

Minimize

- Total variable power system variable generation costs to supply electricity demand for a week
  - Fixed fuel cost consumption
  - Start up and shutdown cost
  - Variable production and operation & maintenance cost
  - CO_2 emission cost

Subject to

- Power system balance
  - Total thermal energy production + total renewable energy production + total non-served energy in the system needs to be equal to the total energy demand in the system in every hour
  - The provision of upward and downward operating reserves for every hour in the system needs to be ensured to respond to unexpected events in the grid. These reserves are estimated to be a percentage of the hourly demand and are provided by the online generating units that can increase or decrease their output over their scheduled output in limited time. For simplicity reasons, reserves have been assumed to be zero.

- Constraints of thermal generating units
  - Total production of committed units. If a generating unit is committed, its production needs to be above the unit's technical minimum output.
  - Generator output must remain below its maximum capacity.
  - Logical commitment constraint. A unit can start up, be committed and shut down in different, consecutive or alternate, periods but it can never start up and shut down simultaneously.
  - Minimum time online and offline. If a unit is committed, it must remain online for a minimum number of hourly periods. Similarly, if a unit is shut down, it must remain offline for a minimum number of hourly periods.
  - The production above technical minimum of the unit + upward reserve of the unit needs to be less or equal to the difference between the unit's maximum capacity and its technical minimum output.
  - The downward reserve of the unit needs to be less or equal to the production above technical minimum of the unit.

- Ramping limits of the units. The increase or decrease in a unit's output has to remain lower than its maximum upward and downward ramp capabilities, respectively.

- Network constraints
  - Capacity limits of the transmission lines. The flow of energy through the AC and HVDC transmission lines needs to remain lower than the maximum capacity of these.
  - Power flow in AC transmission lines. The power flowing through a specific AC transmission line is equal to the net power injection in a node multiplied by a factor (PTDF), and summed over all the nodes in the network that connect to any AC line.
    The net power injection in a node includes production + non-served energy − demand + the net power inflow from HVDC lines connected to that node.
    The factor PTDF relates the net power injection in a node that connects to any AC line, to the flow of the AC line of whose power flow is being calculated.
    The power balance in every node connecting to any AC line is implicitly guaranteed with this equation.
  - Power balance in nodes connecting only to HVDC lines. Production + non-served energy − demand + the net power inflow from HVDC lines connected to that node should be equal to zero.

2.5.1 Objective Function

The unit commitment model's algorithm seeks to minimize the total variable generation costs to supply electricity for one week in the simplified European power system considered. In general terms, these total variable generation costs are defined as the sum of: (i) the fixed fuel consumption costs $C^{Fixed\,Fuel}$, (ii) the variable costs of production C^{SRMC} (ii) the startup and shutdown costs C^{SU} and C^{SD}, (iii) the non-served energy costs C^{NSE} and (vi) the CO_2 emission costs $C^{total\,CO2}$, as shown in equation 2.18.

$$C^{Total} = \min\,\{C^{Fixed\,Fuel} + C^{SRMC} + C^{SU} + C^{SD} + C^{total\,NSE} + C^{total\,CO2}\} \qquad \text{(Eq. 2.18)}$$

The fixed fuel consumption cost is the sum over all the generators g and all hourly periods p of the fixed cost of fuel in €/hour incurred for all thermal generating units (Eq. 2.19). This cost is obtained based on the fixed fuel consumption of the units according to the fuel type used. Units that have lower fixed fuel consumption rates like nuclear fuel, lignite, coal and anthracite units, have a lower fixed fuel cost compared to those units using natural gas, gas or light and heavy fuel oil.

$$C^{Fixed\ Fuel} = \sum_{p\,\in P}\sum_{g\,\in G} C_g^{Fixed\ Fuel} u_{g,p} \quad \text{(Eq. 2.19)}$$

The short run marginal cost (SRMC) of production refers to the marginal cost of the generators. It is calculated over all generators g and all hourly periods p (Eq. 2.20). It includes the production cost and the operation and maintenance cost of the units. The production cost can be approximated to the fuel cost in €/MWh divided by the operating efficiency of the generating unit.

$$C^{SRMC} = \sum_{p\,\in P}\sum_{g\,\in G} C_g^{MC} p_{g,p} = \sum_{p\,\in P}\sum_{g\,\in G}\left(\frac{C_g^{Variable\ Fuel}}{e_g} + C_g^{O\&M}\right)\cdot p_{g,p} \quad \text{(Eq. 2.20)}$$

Startup costs reflect the consumption of fuel required to reach the optimal conditions of temperature and pressure in the boiler of the generating units. This cost is calculated over all generators g and all hourly periods p following equation 2.21, where C_g^{SU} represents the startup cost of unit g per capacity installed, $\overline{P_g}$ is the unit's maximum capacity and $v_{g,p}$ is the unit's binary startup variable. In this model, shutdown costs have been assumed to be a 10% of the startup costs.

$$C^{StartUp} = \sum_{p\,\in P}\sum_{g\,\in G} C_g^{SU}\overline{P_g}\, v_{g,p} \quad \text{(Eq. 2.21)}$$

$$C^{Shutdown} = \sum_{p\,\in P}\sum_{g\,\in G} C_g^{SD} w_{g,p} \quad \text{(Eq. 2.22)}$$

In general terms, the cost of non-served energy is a result of the total amount of energy not supplied in every node and hour, $nse_{i,p}$, multiplied by the cost of non-served energy C^{NSE} in €/MWh calculated over all the nodes i and all hourly periods p as shown in equation 2.23.

$$C^{total\ NSE} = \sum_{p\,\in P}\sum_{i\,\in I} C^{NSE} nse_{i,p} \quad \text{(Eq. 2.23)}$$

The objective function also includes a term for total CO_2 emission costs for those thermal units with an emission rate E_g (tonnes of CO_2/GWh). The emission rate multiplied by the cost of CO_2 emissions, C^{CO2} (M€/ tonnes of CO_2), by the power output of the unit $p_{g,p}$ and summed over all thermal generators g and all hourly periods p gives the total CO_2 emission cost (Eq. 2.24).

$$C^{total\ CO2} = \sum_{p\in P}\sum_{g\in G} E_g C^{CO2} p_{g,p} \qquad \text{(Eq. 2.24)}$$

2.5.2 Constraints

Alongside the objective function several technical constraints exist and they need to be complied with. The following section is devoted to review these constraints.

2.5.2.1 Power system balance requirement.

An energy balance is required between demand $D_{p,i}$ and thermal $(p_{g,p})$ and renewable $(ig_{i,p})$ production at all time periods in the power system. Curtailment of renewable generation is allowed in the model if it is required to comply with system balance. Additionally, a variable for non-served energy is included to take into account situations in which there is a lack of energy production or the network limits the supply of electricity to a particular load center. This is guaranteed with equation 2.25.

$$\forall\, p \in P \qquad \sum_{g\in G} p_{g,p} + \sum_{i\in I}\left[ig_{i,p} + nse_{i,p}\right] = \sum_{i\in I} D_{p,i} \qquad \text{(Eq. 2.25)}$$

2.5.2.2 Production of committed units.

The total production of a unit is modeled in two separate terms, as shown in equation 2.26. On the one hand there is the technical minimum output of the unit once it is committed and on the other hand a term is included in case the output is above that minimum.

$$\forall\, g,p \qquad p_{g,p} = \underline{P}_g u_{g,p} + p^{min}_{g,p} \qquad \text{(Eq. 2.26)}$$

Moreover, the initial behaviour of the units is limited by their initial conditions (Morales-España, et al., 2013). In practice, a day in advance is modeled in order to obtain the initial conditions for the following day. If the initial output of the unit lies above its technical minimum output then the unit is committed.

2.5.2.3 Logical Commitment and Minimum Up and Downtime constraints

The following constraint (Eq. 2.27) guarantees that the commitment, startup and shutdown binary variables take the adequate values between hourly periods.

$$\forall\, g,p \qquad u_{g,p} - u_{g,p-1} = v_{g,p} - w_{g,p} \qquad \text{(Eq. 2.27)}$$

On the other hand, equations 2.28 and 2.29 refer to the minimum number of hourly periods that the units must be online and offline. As specified in (Morales-España, et al., 2013) the combination of these constraints results in $v_{g,p} + w_{g,p} \leq 1$, and this assures that a unit does not start up or shut down simultaneously.

$$\forall g,p \in [TU_g, P] \qquad \sum_{i=p-TU_g+1}^{P} v_{g,i} \leq u_{g,p} \qquad \text{(Eq. 2.28)}$$

$$\forall g,p \in [TD_g, P] \qquad \sum_{i=p-TD_g+1}^{P} w_{g,i} \leq 1 - u_{g,p} \qquad \text{(Eq. 2.29)}$$

2.5.2.4 Generation capacity limits

The proposed formulation from (Morales-España, et al., 2013) for the generators' capacity limits over their production and their upward and downward spinning reserve is constrained by the committed, start up and shutdown status of the units. It is realistic to assume that, immediately after starting up a unit or immediately before shutting down the unit, this one is producing at its minimum level. Equations 2.30, 2.31 and 2.32 assure that, both if a unit is started up in hour p ($v_{g,p} = 1$) or shut down in $p+1$ ($w_{g,p+1} = 1$), the production of that unit in hour p will be its minimum output ($p^{min}_{g,p} = 0$) since the right term $\left(\overline{P_g} - \underline{P_g}\right)$ would be multiplied by zero and $ur_{g,p}$ is defined as a positive variable.

$$\forall\, g \,\in\, G_1, p \qquad p^{min}_{g,p} + ur_{g,p} \leq \left(\overline{P_g} - \underline{P_g}\right)\left(u_{g,p} - v_{g,p}\right) \qquad \text{(Eq. 2.30)}$$

$$\forall\, g \,\in\, G_1, p \qquad p^{min}_{g,p} + ur_{g,p} \leq \left(\overline{P_g} - \underline{P_g}\right)\left(u_{g,p} - w_{g,p+1}\right) \qquad \text{(Eq. 2.31)}$$

$$\forall\ g \nexists G_1, p \qquad p^{min}_{g,p} + ur_{g,p} \leq \left(\overline{P_g} - \underline{P_g}\right)\left(u_{g,p} - v_{g,p} - w_{g,p+1}\right) \qquad \text{(Eq. 2.32)}$$

$$\forall\ g, p \qquad p^{min}_{g,p} - dr_{g,p} \geq 0 \qquad \text{(Eq. 2.33)}$$

It is noted that equations 2.30 and 2.31 are applied for the subset G_1 which contains the generating units with $TU_g = 1$. On the other hand, equation 2.32 is included for those units with $TU_g \geq 2$, this is when the units are operating for at least two online periods. Although equation 2.30 and 2.31 are feasible for both when $g \in G_1$ and when $g \nexists G_1$, using the combination of Eq. 2.30, 2.31 and 2.32 provides a tighter and more compact formulation. The reader can refer to (Morales-España, et al., 2013) for more information about the use of this formulation.

2.5.2.5 Upward and downward system operating reserves

The following constraints (Eq. 2.34 and Eq. 2.35) ensure the provision of upward and downward operating reserves for every hour in the system. These reserves, provided by the online generating units, are defined as the power that these units can increase or decrease over their programmed output within a limited time in response to an automatic generation control (AGC). For simplicity reasons, reserves are assumed to be zero.

$$\forall\ p \in P \qquad \sum_{g \in G} ur_{g,p} \geq 0 \qquad \text{(Eq. 2.34)}$$

$$\forall\ p \in P \qquad \sum_{g \in G} dr_{g,p} \geq 0 \qquad \text{(Eq. 2.35)}$$

2.5.2.6 Ramping limits

Equations 2.36 and 2.37 ensure that the upward and downward ramp rate limits of all the units are respected.

$$\forall\ g, p \qquad p^{min}_{g,p} + p^{min}_{g,p}{}_{g,p-1} \leq RU_g \qquad \text{(Eq. 2.36)}$$

$$\forall\ g, p \qquad -p^{min}_{g,p} + p^{min}_{g,p}{}_{g,p-1} \leq RD_g \qquad \text{(Eq. 2.37)}$$

2.5.2.7 Network constraints

The power flow in AC transmission lines is calculated using a linearized approximation of the AC power flow problem: the DC power flow model. The Power Transfer Distribution Factors (PTDF) are calculated as the result of the linearization process. This simplification is based on a series of assumptions previously explained in section 2.2.

For every hourly period and for every AC transmission line in the network, the active power flows in these lines are calculated using the linear relationships (PTDFs) between the active power flows and the net power injections in the subset of nodes that connect at least one AC transmission line (i_{AC}) (Eq. 2.30). These net power injections are obtained from the power balance in every bus; it includes the total thermal and renewable generation, the demand, the non-served energy and the injections due to the power flows in the HVDC lines connected to the node in question. Equation 2.30 implicitly ensures the power balance in those nodes that are connected to at least one AC transmission line.

$$\forall p, ij_{AC\ i,j,c} \quad pl_{AC\ ij,c,p} = \sum_{i_{AC} \in I} PTDF_{ij,c,i_{AC}} \left[\sum_{g \in gen\ i_{AC},g} \left(\underline{P_g} u_{g,p} + p_{g,p}^{min} \right) + ig_{i_{AC},p} - D_{p,i_{AC}} + nse_{i_{AC},p} + \sum_{l \in L} A_{DC\ l,i_{AC}} \cdot pl_{DC\ l,p} \right] \quad \text{(Eq. 2.30)}$$

Regarding the power flows in the HVDC lines ($pl_{DC\ l,p}$), these are calculated through the power balance equation of those nodes in the network connected only to HVDC lines (Eq. 2.31).

$$\forall p, i_{DC} \in I \quad \sum_{g \in gen\ i,g} \left(\underline{P_g} u_{g,p} + p_{g,p}^{min} \right) + ig_{i,p} - D_{p,i} + nse_{i,p} + \sum_{l \in L} A_{DC\ l,i} \cdot pl_{DC\ l,p} = 0 \quad \text{(Eq. 2.31)}$$

Moreover, Eq. 2.32 and Eq. 2.33 ensure that the transmission line capacities are respected in both AC and HVDC lines.

$$\forall\ p \in P \quad -\overline{P}_{AC\ ij,c} \leq pl_{AC\ ij,c,p} \leq \overline{P}_{AC\ ij,c} \quad \text{(Eq. 2.32)}$$

$$\forall\ p \in P \quad -\overline{P}_{DC\ l} \leq pl_{DC\ l,p} \leq \overline{P}_{DC\ l} \quad \text{(Eq. 2.33)}$$

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CHAPTER 3

SIMULATION SETUP

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3. Simulation Setup

Until now, the focus has been set on the theory and application of unit commitment and economic dispatch models for the present research and to the approach used to model the proposed power market designs.

The following chapter discusses the renewable scenarios used and the assumptions made in the optimization model that will serve to analyse how well the different power market designs accommodate the different degrees of renewable energy sources integrated in the power system.

Moreover, sections 3.2 and onwards give a description of the input data and its sources. Demand, operating reserves, the properties of the generators and their costs, renewable generation and the parameters of the network are identified and used in the formulation previously presented.

3.1. Scenario definition

Five future scenarios with different degrees of renewable energy integration in Europe are used to help assess the degree of uncertainty that a long-term generation adequacy assessment entails. Moreover, these scenarios help evaluate the evolution of key parameters relevant to a proper functioning of the European interconnected power system. Trends on nodal electricity prices, the degree of power line congestions, curtailment of renewable generation and the evolution of the system's total variable operation costs over the three proposed power market designs is the main focus of the scenario analysis.

The scenarios are based on the Scenario Outlook & Adequacy Forecast (SO&AF) from 2014 to 2030 (ENTSO-E, 2014a), which are annually published by the ENTSO-E, as part of the Ten-Year Network Development Plan (TYNDP) (ENTSO-E, 2014b).

The Scenario Outlook & Adequacy Forecast report sets out three scenarios (Scenario A "Conservative", Scenario B "Best Estimate" and Scenario EU 2020) and four visions for 2030. In these scenarios generation and demand forecasts are specified for all Member States and the adequacy of the ENTSO-E's interconnected power system is assessed on the mid and long-term horizon focusing on power balance, margins, energy indicators and the generation mix. Thus, it provides stakeholders in the electricity sector with what the future holds on the European level. The specific scenarios used in this research are the following:

- Scenario B "Best Estimate", as the reference scenario for year 2014.
- The EU 2020 Scenario.
- The four Visions for 2030.

These scenarios are non-probabilistic, instead they have associated estimations of the generation mix and the demand profiles. The details on the assumptions on which these scenarios are built are shown in the next subsections. Figure 3.1 gives an overview of the generation mix for the considered network across the chosen scenarios.

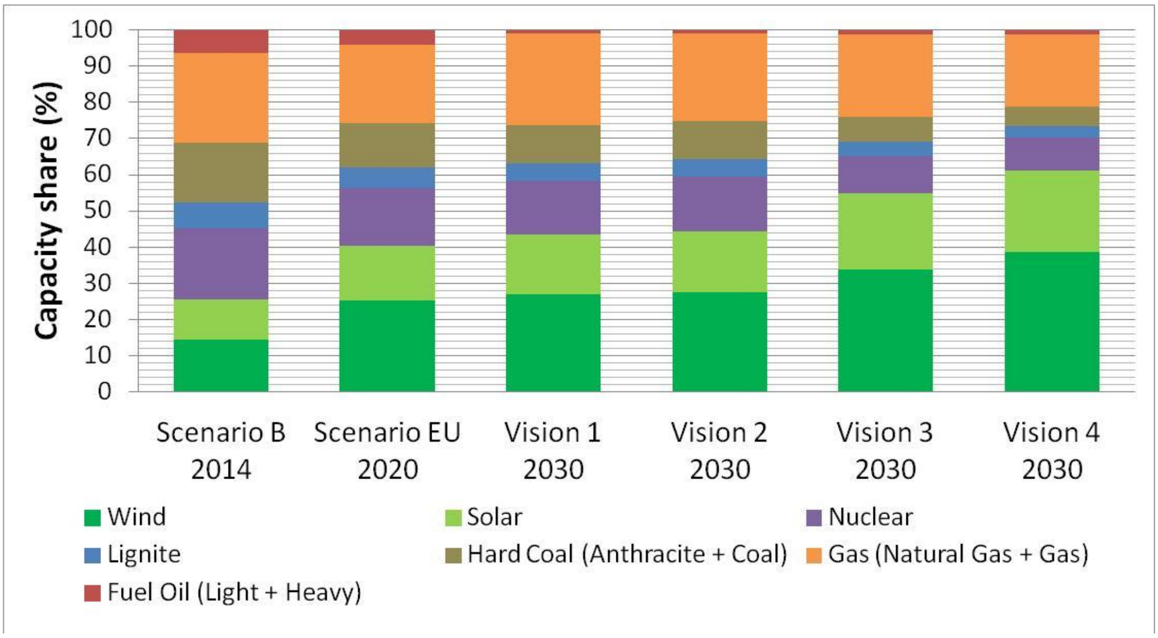


Figure 3.1. General overview of the generation mix across all scenarios.
Source: Own source, calculated with the input data in the model.

In relative terms, it can be noted that the share of installed renewable capacity in the entire power system considered is expected to increase from 26% in 2014 to 61% in year 2030 while all the thermal technologies decrease in share. Along with this general decrease of thermal power plants, the lowest capacity values of coal-fired steam power plants are spotted in Vision 3 (51,7 MW). This is combined with the highest capacity values of gas-fired steam power plants and combined-cycle gas turbines in Vision 3, which increase by 27% with respect to the capacity installed in scenario EU 2020 (see Table B.2 in Appendix B). Therefore, there is a clear shift expected towards renewable sources and, consequently, a need for flexible responsive technologies to react in case of sudden lack of wind or sun.

3.1.1. Reference scenario

Scenario B "Best Estimate" is used as the reference base case scenario to model the current situation in the year 2014. It is a bottom-up scenario based on the TSOs' expectations of potential developments for the period 2014 to 2025 given that market signals incentivize investments.

In terms of generation mix, this scenario takes into account the generation capacity considered to be as sure and whose commissioning is under process as well as the future commissioning of power plants considered as credible according to the TSOs' available information. The request to obtain connection to the grid by producers is not the only source of estimation used by the TSOs to consider the likelihood that a project takes place, but also the regional economic assessments of these are taken into account.

Figure 3.2 shows the generation mix per country used to model the network in year 2014 (See associated Table B.3 in Appendix B). The share of renewable installed capacity is well below 30% except in countries like Germany, Norway or Denmark, which already have significant amounts of solar plants and wind farms, respectively. For further political and economical viewpoints considered in this scenario the reader can refer to the Scenario Outlook & Adequacy Forecast 2014-2030 (ENTSO-E, 2014a).

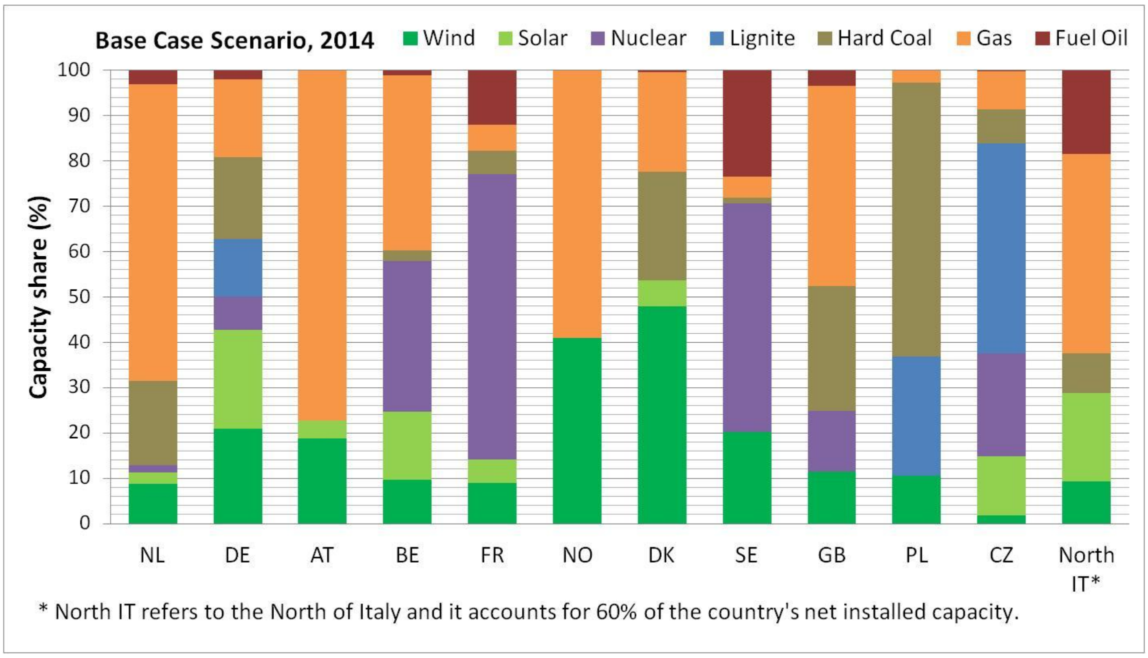


Figure 3.2 . Breakdown of generation mix per country in Scenario B year 2014.
Source: Own source, calculated with the input data in the model.

3.1.2. Scenario EU 2020

Scenario EU 2020, built from a top-down approach, is derived from the National Renewable Action Plans (NREAP) of the member states or from the equivalent governmental plan in case of lack thereof. It gives an estimation of the required future renewable energy developments to comply with the European 20-20-20 objectives. Conventional generation capacity forecasts that support the European renewable plan are also envisaged on a national basis. Moreover, the assumptions in this scenario also serve as an important tool for the ENTSO-E's analysis related to the requirements for future grid development.

Compared to Scenario B, the difference of both scenarios is reflected between the number of projects that are likely to happen given the regional market incentives with the number of projects needed to meet a set of political objectives on a European level. In this respect, and provided that all countries meet their national renewable targets, Figure 3.3 shows that almost all countries increase their renewable capacity share to at least 30%. (See associated Table B.4 in Appendix B).

Simultaneously, there is a considerable decrease in the system of coal-fired power plants (lignite and hard coal) (12%) and fuel oil plants (27%) with respect to the reference scenario. Nuclear power plants share drops by a 4,5% while gas-fired plants and CCGTs slightly increase their share by 3,8%. For further political and economical viewpoints considered in this scenario the reader can refer to the Scenario Outlook & Adequacy Forecast 2014-2030 (ENTSO-E, 2014a).

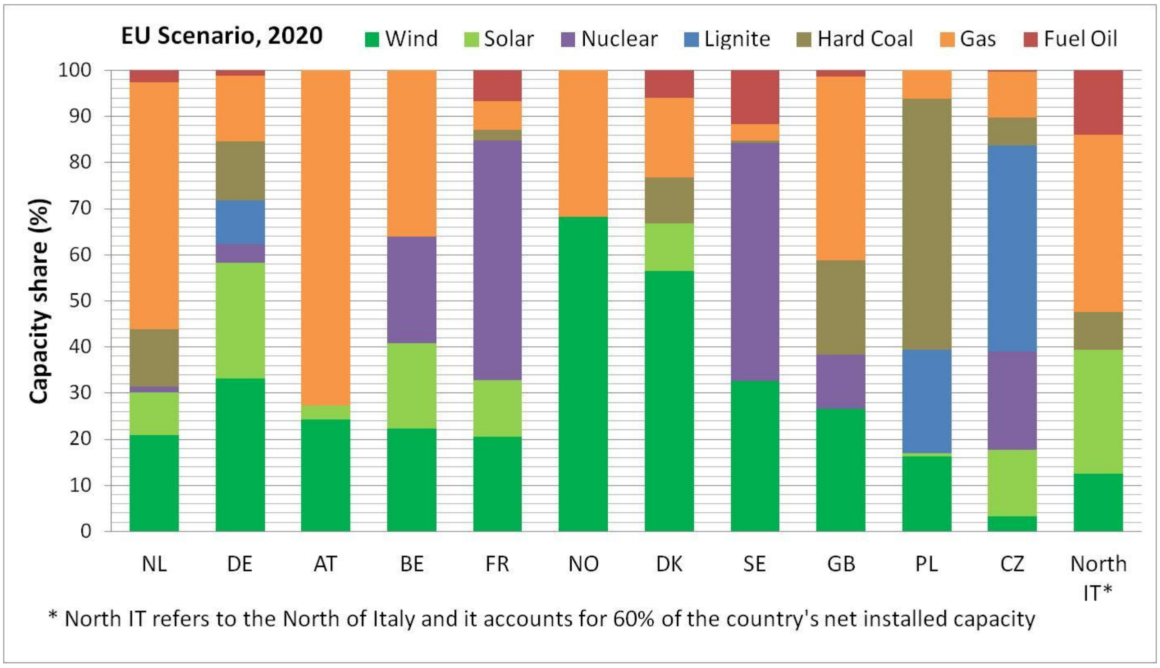


Figure 3.3 . Breakdown of generation mix per country in Scenario EU year 2020.
Source: Own source, calculated with the input data in the model.

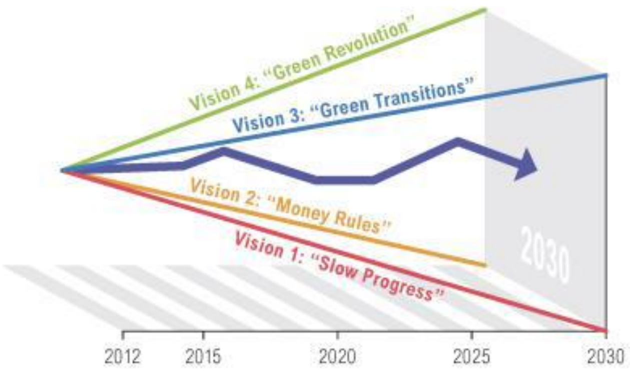
3.1.3. The Visions for 2030

The year 2030 serves as a bridge between the European energy targets of 2020 and 2050. The four Visions presented in the ENTSO-E Scenario Outlook & Adequacy Forecast are conceptually different from the scenarios shown until now. There are no probabilities associated to them but they are also not forecasts. Taking into account the high uncertainties of such long-term predictions, quantitative data is gathered for the four Visions based on public economic analyses, existing European documents and previous ENTSO-E market studies, such as the Pan-European Market Modeling data used for the Ten Year Network Development Plan (TYNDP), 2014.

The aim of these Visions is to estimate the extreme values between which the actual evolution of parameters in the system is expected to lie (ENTSO-E, 2014a). It differs from the objective of scenario B and scenario EU 2020, which estimate the actual evolution of parameters under different assumptions.

The Visions are named as following:

- Vision 1 - Slow Progress
- Vision 2 - Money Rules
- Vision 3 - Green Transition
- Vision 4 - Green Revolution



Source: TYNDP, (ENTSO-E, 2014b).

Underlying every Vision there are significantly different assumptions. Visions 1 and 3 are built from a bottom-up approach with each country's energy policy and assume thereby a weak integration of the European energy market, with Vision 1 assuming an overall delay in the energy goals of 2050 and Vision 3 considered to be on track with these policy goals.

On the other hand and in contrast to the above, Visions 2 and 4 are built from a top-down approach, and assume a strong integrated European market. The generation mix development strategy is derived from Visions 1 and 3 after a harmonization of the data from all countries.

Figure 3.4 and Figure 3.5 give a brief overview of the political and economical frameworks and the generation and demand assumptions under which the Visions are built, respectively. For further details on these assumptions, the interested reader is referred to the Scenario Outlook & Adequacy Forecast 2014-2030 (ENTSO-E, 2014a).

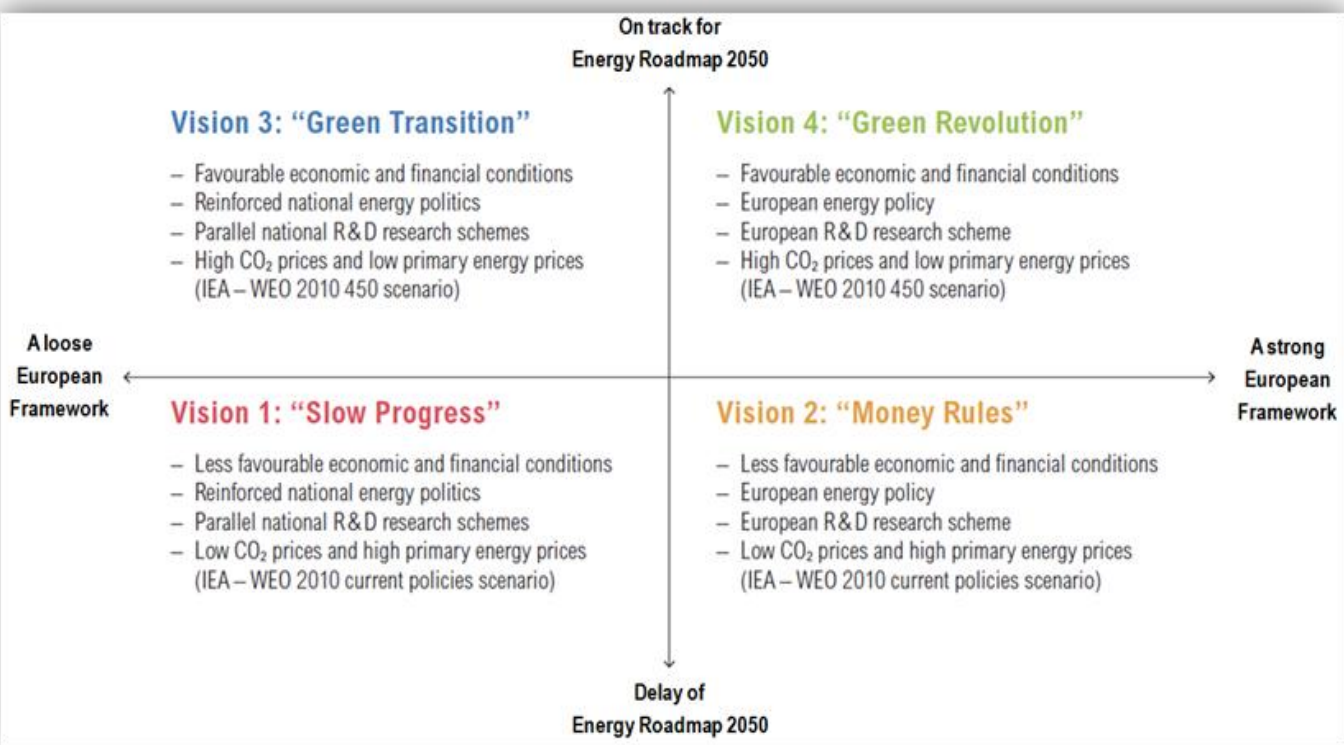


Figure 3.4. Political and economic frameworks of the four Visions. Source: TYNDP 2014.

Figure 3.5. Generation and load frameworks of the four Visions. Source: TYNDP 2014

Figure 3.6 and Figure 3.7 show the breakdown of the generation mix per country for Vision 1 and Vision 4. Appendix B contains the analogous figures for Visions 2 and 3, and the associated Tables Table B.5 to Table B.8 in Appendix B.

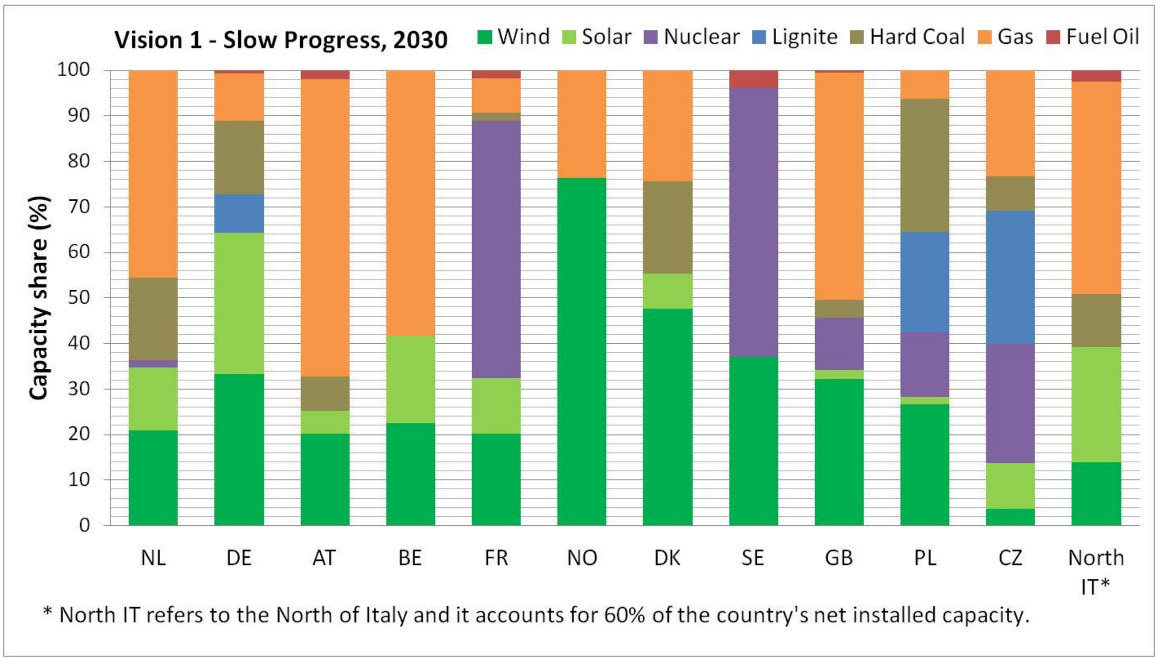


Figure 3.6 . Breakdown of generation mix per country in Vision 1 year 2030.
Source: Own source, calculated with the input data in the model.

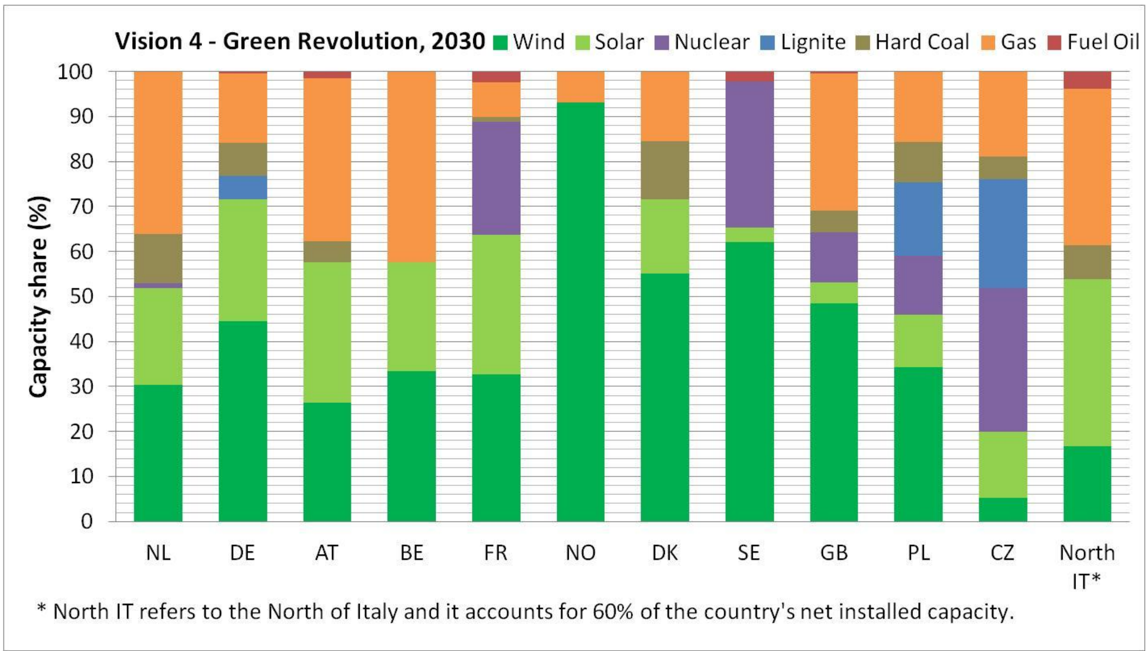


Figure 3.7 . Breakdown of generation mix per country in Vision 4 year 2030.
Source: Own source, calculated with the input data in the model.

3.2. Model Data

The optimization model used to model part of the European power system is very data intensive due to the large number of parameters required related to generating units and transmission lines. The next subsection describes the input parameters in the model, the assumptions adopted and the sources used.

3.2.1. Demand

In terms of load forecast, the best national estimate by the TSOs is used. The load estimation is based on demography, economic growth and energy efficiency policy assumptions.

Hourly load values in MW for all the countries in the study were collected for the second week (from day 7 to day 14) of January and July 2014. These demand time series were obtained from the ENTSO-E consumption data portal. These two different weeks in the year were selected in order to account for seasonal differences in the demand profile and in the type of technologies used.

The year 2014 was chosen for the reference scenario presented in section 3.1 since it was the latest available online data and it fits with the scenario B for 2014 from the ENTSO-E. The same time series from 2014 is used for the scenario EU 2020 and it is scaled by applying to it an annual percentage demand increase (see Table C.1 in Appendix C). As for the Visions for 2030, the time series obtained from the TYNDP (ENTSO-E, 2014b) are used instead.

Given that in the considered network in some cases there are multiple nodes per country, the approach followed to allocate the total hourly demand value of each country is to divide this value of the demand proportionally to the population in the region covered by every node. In this way, demand values are obtained for every hourly period and every node of the network. Population data is retrieved from national statistics websites of the different countries. Table C.4 in Appendix C shows the criteria used to divide the country into their corresponding number of zones and assign them to each and every node.

On the other hand, in the case that the hourly demand in any node cannot be fully met due to transmission constraints or lack of generation capacity, a high penalization cost is introduced in the objective function of the optimization problem, as already stated in section 2.5.1, in order to minimize this term as much as possible. The cost parameter used for the non-served energy cost amounts to 200 €/MWh. This magnitude is higher than the most expensive generator in the system, with a marginal cost of 111 €/MWh, and it lies in the range of the marginal costs of peak plants in balancing markets. In case there is a large unbalance in the system, these power plants will likely be called upon in the balancing market to meet these system unbalances.

3.2.2. Generator properties

Generating units have three different types of properties: cost properties, technical characteristics and properties related to their initial operating conditions. In the subsections below follows a description of the assumptions made regarding the required input parameters of these units.

3.2.2.1. Generator costs

Financial characteristics of generators depend on the type of technology in question. Since the model is focused on the short-term planning and schedule of the units for the day-ahead market, fixed costs and capital investments are not included. From among a unit's variable costs, it is relevant to differentiate between the following cost parameters:

- Fuel cost
- Fixed fuel cost
- Operation & maintenance cost
- Short-run marginal cost
- Startup & shutdown cost

It is not the same to operate a nuclear power plant or a gas-fired steam turbine based power plant. The plant's flexibility in terms of response reaction to startup and shutdown commands is directly connected to its operational costs. A nuclear power plant is less flexible and has lower operational costs.

Fuel cost

According to the type of technology employed, the fuel used will be more or less expensive. This is reflected in this parameter which defines the cost in Euros of fuel used per MWh of energy produced of every thermal generator. Average values are obtained from (Neuhoff, et al., 2013) and are shown in Table D.1 in Appendix D.

Moreover, some random variability is introduced in the fuel cost of every generator understanding that the cost of every technology will not be the same for all generators spread in the network. Therefore, a random maximum value of +/- 10 % of the average value is added to the input parameter.

Fixed fuel cost

This parameter refers to the cost of the fixed amount of fuel that is required or consumed during the time that the thermal generator is turned on. Again, it depends on the fuel type of the generator and it is measured in Euros per hour. Figure 3.8 shows the linear approximation of the input-output characteristic of a generic generator g. The term $\beta_g$represents the fixed fuel consumption in thermie per hour and α_g the variable consumption in thermie per MWh. See Appendix D for more information.

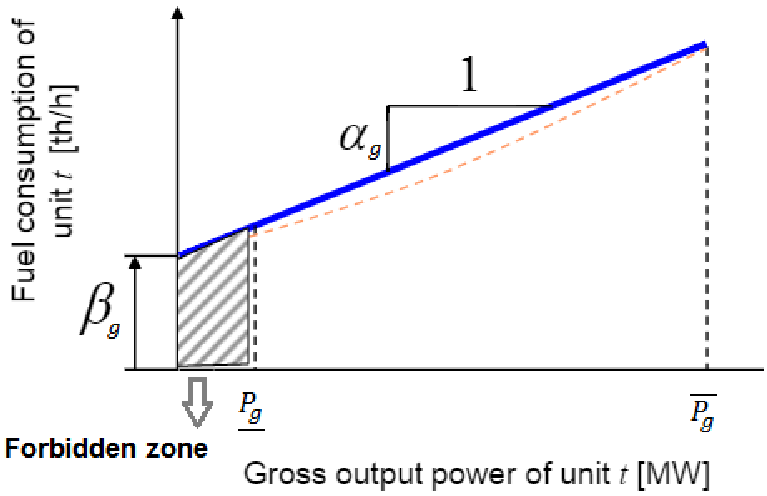


Figure 3.8. Linear approximation of input-output characteristic of generator g.
Source: Adapted figure from Comillas University.

Operation & maintenance cost

According to the type of fuel, this parameter is defined as the cost to operate and maintain a generating unit in Euros per MWh of energy produced. In a similar way, and in order to facilitate the algorithm to choose the most cost-effective generators, a variation of +/- 10 % is introduced with respect to the average cost shown in Table D.3 in Appendix D.

Short-run marginal cost (SRMC)

This parameter corresponds to the overall variable cost of a generator g and it equals:

$$SRMC_g\left(\frac{€}{MWh}\right) = \frac{Fuel\ cost\ \left(\frac{€}{MWh}\right)}{Operating\ efficiency\ (\%)} + O\&M\ (€/MWh)$$

The average operating efficiency values of the different types of technologies are shown in Table D.4 in Appendix D and are taken from (Neuhoff, et al., 2013).

Startup & shutdown costs

The cycling process of thermal power plants is becoming more and more relevant in power systems with increasing penetration of renewable sources since it is closely linked to the operational flexibility of the thermal plants. Starting up and shutting plants down has a degenerative effect on the units' components due to sudden variations in temperature and pressure accelerating failures and outages (Van den Bergh & Delarue, 2015). Therefore, the power plant cycling process has associated startup and shutdown costs.

The startup cost in this model has been defined as the cost in million Euros per GW of installed capacity of starting up the generator unit from a "cold" status. Additionally, startup costs consist of direct and indirect startup costs. Table D.5 in Appendix D shows the adopted startup costs in the model, taken from (Van den Bergh & Delarue, 2015).

- Direct startup cost (€/△MW) - Reflects the cost of fuel consumed needed to reach the optimal conditions of temperature and pressure in the power plant's boiler, as well as the CO_2 emissions and auxiliary services during the startup process. In reality this cost is a function on the time the unit has been shut down. For simplicity reasons, it is assumed this is constant.
- Indirect startup cost (€/△MW) - Incorporates the long-term cycling costs such as the capital replacement and maintenance costs into a short-term operational horizon.

Regarding the shutdown costs, this cost is incurred due mainly to the waste of fuel when the thermal generator has been disconnected from the grid. Besides, it can represent the wearing off cost due to startup and shutdown operations that reduce the plant's lifetime. A 10 % of the startup cost is considered for this parameter.

3.2.2.2. Technical and environmental characteristics

Thermal generators' technical characteristics such as the upward and downward ramping limits, the minimum technical output, the minimum online and offline times or CO_2 emissions rate determine among other factors in the model the units' utilization rates. This subsection presents the assumptions made for each of the following generator's parameters:

- Maximum output
- Minimum technical output
- Upward and downward ramp limits
- Minimum online and offline times
- CO_2 emission rate

Maximum output

The maximum output of a generator corresponds to the capacity installed of that generator. The capacity of every generating unit is obtained by using the ENTSO-E's Scenario Outlook &

Adequacy Forecast mentioned in section 3.1. The country's installed capacity for the corresponding fuel type, country and scenario (scenario 2014, 2020 and the Visions for 2030) is divided by the number of units of the corresponding fuel type and country.

The number of generators assigned to every node of the network is estimated such that the above calculation gives installed capacity values that lie within a realistic range. The number of units of every type of technology is assumed to be the same across scenarios.

In Appendix D, Table D.6 to Table D.11 show the capacities of the generators used for every fuel type, country and scenario.

Minimum technical output

The minimum technical load required for every generator is assumed to be a percentage of the nominal maximum output. Table D.12 in Appendix D indicates the adopted values according to the type of technology taken from (Neuhoff, et al., 2013).

.**Upward and downward ramping limits**

Upward and downward ramp limits define by how many MW can the generator increase or decrease its power output in one hour, respectively. Same load gradient is defined for both upward and downward limits, see Table D.13 in Appendix D. Values were taken from Comillas University model prototypes.

Minimum online and offline times

Flexibility of conventional generation technologies is a very important feature to measure in a power system with an increasing share of renewable generation. However, due to both technical and economical reasons, once a unit is connected or disconnected from the grid this one has to remain connected or disconnected, respectively, for a minimum amount of time. Given the lack of data for this specific parameter, the "cold" startup time from (Eurelectric, 2011) was assumed as a good approximation, see Table D.14 in Appendix D. Both minimum online and offline times are considered to be the same.

CO_2 emission rate

Every generator unit emits certain amounts of CO2 depending on the technology used and has a certain annual energy output. The CO2 intensity of each generator (tCO2/MWh) is the emission rate. This parameter is calculated with the available annual CO_2 emissions and the annual energy output from Enipedia database (TUDelft, 2014). The data from Enipedia is the projection for year 2020 and the same value is used in all scenarios.

The amount of CO_2 emissions produced in the power system is included as a term of the objective function. The aim is to minimize this term by including a high penalization cost for emitting. This cost, also included as a model parameter, is referred to as the CO_2 emission cost rate and its value is set to 100 Euros/tonnes of CO_2 taken from the (European Commission,

2013) ensuring compliance with European regulatory rules. Knowing that the chosen value is presumably high in the range of possible actual values in the ETS trading scheme, a sensitivity analysis will be performed with a reduced value of the base case CO_2 emission cost rate and changes in the generation costs and generation dispatch profiles will be analysed.

3.2.2.3. Initial conditions

The initial conditions of the generators such as the unit's status, its output and the initial time status need to be fixed beforehand in order to get a realistic behaviour of the units in consecutive periods.

Initial output

The model is run for one week plus one day in advance. This day in advance is used to specify the initial output of every generator. The 24th hour of that day sets the initial conditions for the actual week that wants to be modeled. These initial conditions are calculated for every scenario defined and for comparison purposes, the three studied power market designs (Nodal, Zonal and Copper Plate) use the same initial conditions.

Initial commitment status

Once the initial output of the units is specified, and by using Morales-España et al. (2013) formulation, the initial commitment status is determined depending on whether the initial output is greater or smaller than the minimum technical output of the unit.

Initial time status

This parameter indicates the time in hours that the generator has been online or offline. It is assumed that in case the initial output of the unit is zero, the initial time status equals to minus the minimum offline time; in other words this is the minimum time that the generator has to be off. In case the initial output is different from zero, the initial time status equals to the minimum online time; this is the minimum time the generator has to be switched on (Morales-España, et al., 2013).

3.2.3. Renewable generation

Renewable energy sources are not distributed evenly over the European continent and also not over the considered network. Solar and wind energy represent 15,7% share of renewable generation in 2013 (Eurostat, 2015) and this share is expected to drastically increase in the following years. Therefore, these two renewable technologies are used in the research. Solar energy is more available in countries like France, Austria, north of Italy and south of Germany

(Figure 3.9), while there is higher potential for wind energy in northern coastal and offshore regions of the continent (Figure 3.10).

Normalised hourly profiles from the year 2014 are used to input the renewable generation in all scenarios. These profiles are based on the wind speed and solar irradiation estimations in every node of the network taken from a worldwide wind and solar database for the year 2014 (Saha, et al., 2011). These estimations are calculated based on standard turbines power curves (Wijnja-Vlot, 2015).

The hourly renewable generation input parameter is defined as the maximum hourly wind and solar energy produced, and since curtailment is allowed in the model, it is possible for the algorithm to determine less renewable generation in some hourly periods.

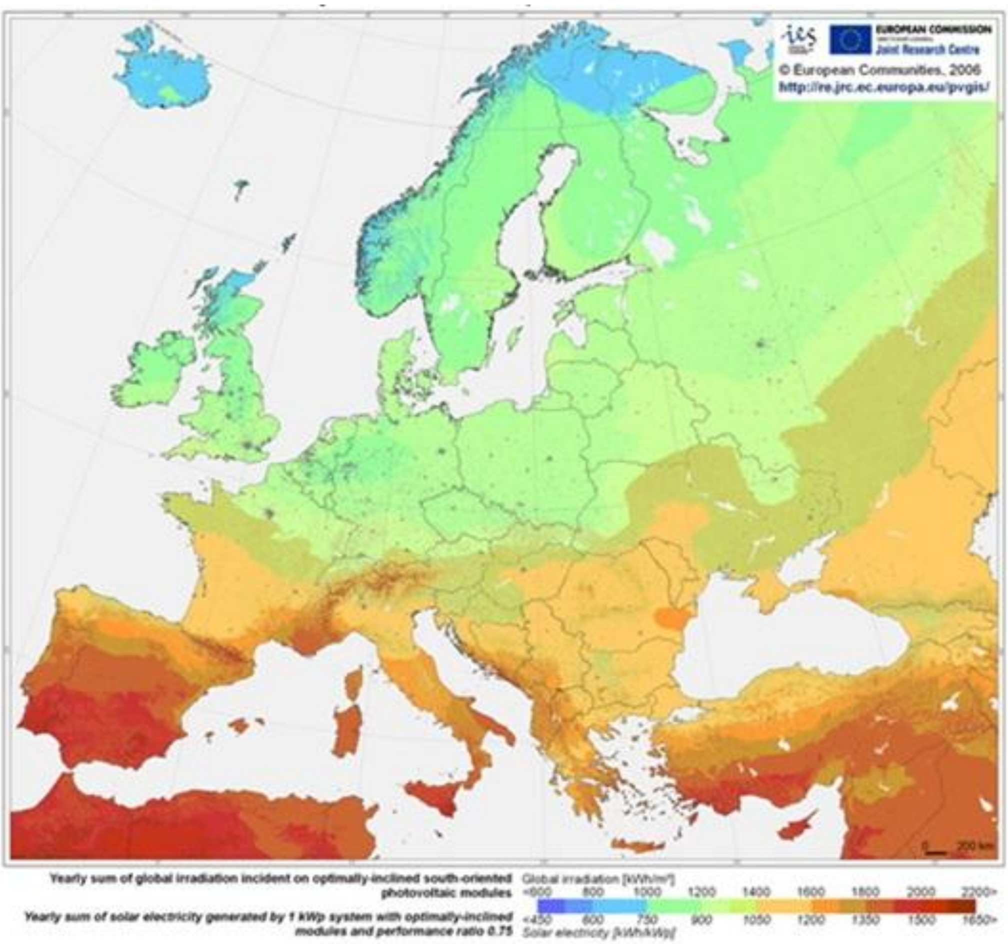


Figure 3.9. Global irradiation (kWh/m^2) (above) and solar electricity (kWh/kWp) (below) in European countries. Source: European Photovoltaic Technology Platform, 2006.

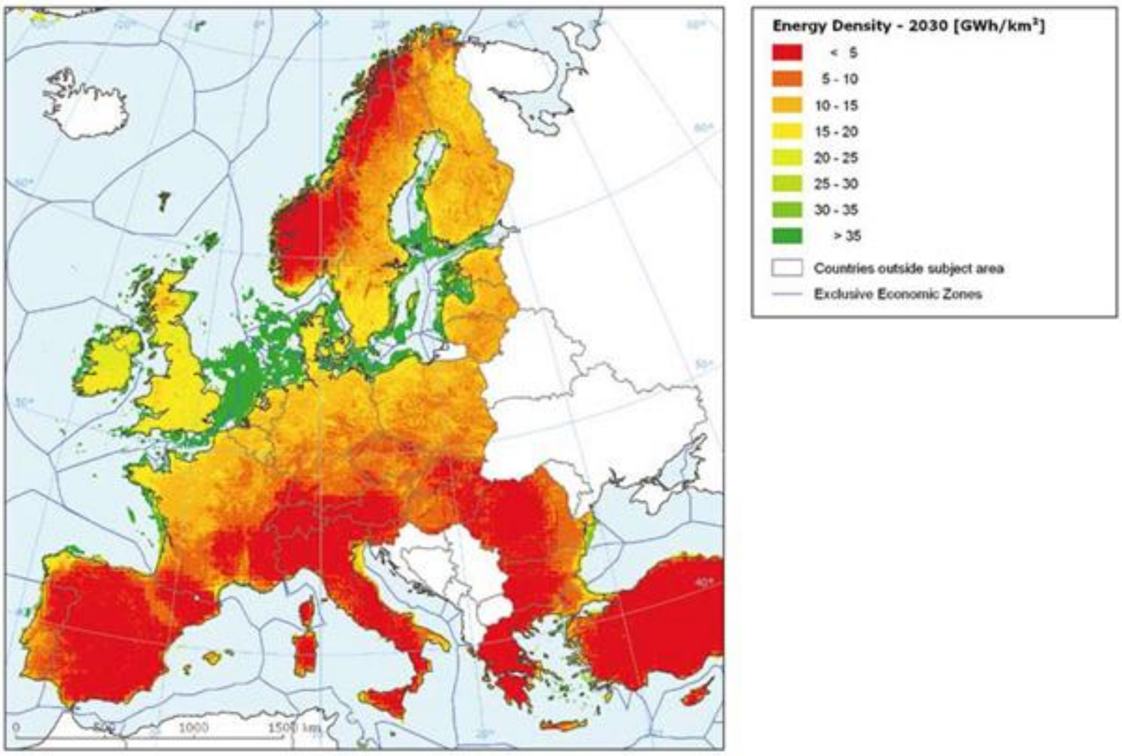


Figure 3.10. Distribution of wind energy density (GWh/km^2) in Europe for 2030.
Source: European Environment Agency, 2008.

With the wind and solar installed capacities from the Scenario Outlook & Adequacy Forecast 2014-2025 (ENTSO-E, 2014a), and by multiplying these capacities allocated in every node by the normalised generation profiles, the actual generation profile is obtained in every node and for every scenario. Both onshore and offshore installed capacities are included given that it is estimated that a large share of the future wind capacity will be due to offshore wind farms.

Each country's wind and solar installed capacities are allocated equally among the country's nodes. In other words, this means that in Germany's five nodes, a 20% of the country's installed capacity for both wind and solar is assigned in every node. Table B.9 and Table B.10 in Appendix B shows the installed capacity for wind and solar technologies for every country and every scenario.

3.2.4. Network parameters

Transmission line capacities and line reactances are probably among the most important input parameters in the model. These can largely affect the output of the unit commitment schedule and power flow output. It should also be noted that there was no access to official data so educated estimations were made in order to stay as close as possible to reality.

3.2.4.1. Transmission line capacities

Transmission line capacities are defined as the maximum power a particular line can withstand in normal operational conditions. According to the network topology defined in Van Blijswijk, et al., (2015), some of the transmission corridors have more than one line circuit, considering them lines in parallel with the same power capacity.

A sensitivity analysis will be performed by reducing and increasing by 50% the capacity of the intra-zonal transmission lines with respect to the base case values. The intra-zonal lines are the ones within zones, i.e. countries.

3.2.4.2. Inductive reactances

As mentioned before, the inductive reactances of every line circuit becomes an important input parameter since the Power Transfer Distribution Factors (PTDF), and hence the power flows are determined by the relation between these reactances.

This network parameter is usually not made publicly available. Therefore, an average unitary reactance of the Dutch power grid equal to $x_{average} = 0.27\ \Omega/km$ is used as the reference unitary reactance for the considered network (Van Blijswijk, 2011). Since the lengths of the power lines are available, the reactances can be easily obtained. For the exact calculations of the line reactances, the reader is referred to Appendix D.

CHAPTER 4

SIMULATION RESULTS

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4. Simulation Results

The following chapter presents the results obtained from the optimization model for the defined scenarios and the studied power market designs and it deals with the main research question and the second research sub-question. Discussions of the results are done baring in mind the limitations of the research.

In subsequent sections the power system's variable generation costs, the degree of renewable energy curtailed, the system's economic generation dispatch profiles and the degree of non-served energy in the system are discussed. The extent to which the mentioned system parameters are influenced by the amounts of renewable energies and by the design of the power market in place is further developed here.

4.1. Power System Generation Costs

The main aim of this research is to gain a better insight on the functioning of the North-Western and Central Europe's power system under different market designs and for different degrees of renewable integration, as well as to obtain a rough order of magnitude of the effect of these two dimensions on the total variable generation costs of the power system.

As a reminder to the reader, the model's objective function expresses the minimization of the total variable generation costs of the system. Fixed costs related to new investments in generation are out of the scope of this research. The variable generation costs include startup, shutdown and fixed fuel consumption costs, which are fixed costs incurred due to the scheduling of the generating units, and variable operation costs due to the generators' production, CO_2 emissions and the non-served energy.

The results show that in a high renewable scenario, more specifically for Vision 4, the total variable generation costs of the power system when it operates under a zonal power market are around 0,32% higher than if the power system operates under a nodal market, see Table 4.1. While in the first phase of the zonal market (Zonal Phase I), generation costs are around 0,8% cheaper than under a nodal market, this difference is reversed and increased to 0,32% after the redispatch process (Zonal Redispatch Phase) is carried out by the TSOs.

A redispatch phase in a zonal market is required in order to adjust the scheduled generation in accordance to the limits of the network. The research shows that redispatch costs in the high renewable scenario amount to 19 Million Euros (1% of total variable generation costs) for the whole system and for a weekly operation, while in the reference scenario these are significantly smaller, over half the amount, 9,5 Million Euros (0,57% of total variable generation costs) (see Table 4.1). Knowing that future extensions of network infrastructure are not accounted for in the model, and therefore knowing that redispatch costs in Vision 4 could actually be lower due to more cross-border interconnections helping in alleviating congestions in intra-zonal lines, the redispatch process would still be necessary to completely fix the intra-zonal congestions.

Furthermore, the magnitude of the redispatch costs (19 Million Euros) is close to that of the fixed generation costs, which depend in turn on the scheduling of the units. This points out the inefficiency of the power system functioning under a zonal market. Given that the network constraints are not jointly taken into account in the market clearing, the redispatch phase will be inevitably necessary in the highly-meshed European network and will therefore add an extra cost and an operational burden to TSOs.

Table 4.1. Breakdown of generation, non-served energy and redispatch costs for Scenario B (2014) and Vision 4 (2030) for the three proposed power market designs.

Costs (Million Euros)	Copper Plate	Nodal	Zonal Phase I	Zonal Phase I vs. Nodal (%)	Zonal Redispatch Phase	Zonal Redispatch Phase vs. Nodal (%)
Vision 4 (High RES scenario)						
Total Variable Generation	1462,3	1882,8	1866,9	-0,8	1888,9	0,32
Fixed Generation	27,2	28,6	28,0	-2,3	28,0	-2,30
Operation	1432,3	1798,6	1783,7	-0,8	1802,7	0,23
Non-served energy	2,8	55,6	55,2	-0,8	58,2	4,72
Redispatch	-	-	-		19,0	
Scenario B 2014 (Low RES scenario)						
Total Variable Generation	1559,9	1640,6	1640,5	0,0	1659,9	1,17
Fixed Generation	10,2	11,6	11,6	0,1	11,6	0,15
Operation	1549,7	1627,2	1627,0	0,0	1636,4	0,57
Non-served energy	0,1	1,9	2,0	4,7	11,9	531,66
Redispatch	-	-	-		9,5	

On the other hand, the absolute difference in total variable generation costs between nodal and zonal markets for Vision 4 is 6,1 Million Euros (see Table 4.1). This weekly difference in costs would translate into 317,2 Million Euros of annual savings under a nodal market. Neuhoff, et al., (2013) estimates annual savings ranging from 0,8 Billion Euros to 2 Billion Euros under a nodal market, depending on the penetration of renewables considered. Taking into account the simplifications made on this thesis network compared to the one used in Neuhoff, et al., (2013), the result obtained in this research is believed to be in line with the range estimated by Neuhoff.

With regard to the reference scenario, there is a larger difference, 1,17%, between the nodal and zonal power market schemes with respect to the high renewable scenario. However, similarly to before, the increase in variable generation costs can be observed in the redispatch phase of the zonal market (see Table 4.1). Given the much lesser amount of renewable capacity available in the system in this scenario, more expensive generating units are in charge of amplifying the difference in relative terms between nodal and zonal in a low renewable scenario.

Additionally, both market designs have relatively similar generation costs as those that would be expected in a copper plate market, in which one single electricity price would be established for the whole of the European power system (see Figure 4.1). A copper plate market design is used, as already explained, as a theoretical reference and has little real meaning, since it is based on the unrealistic assumption that the power system has unlimited network capacity to supply cost-efficient electricity to everywhere in the network. However, it can still be used as a reference because it highlights the increasing value of transmission with higher renewable energies in the system.

Furthermore, when comparing each market design between both renewable scenarios, Table 4.2 shows that total variable generation costs increase in both nodal and zonal cases in Vision 4 by 14,8% and 13,8%, respectively, while in the case of a copper plate market, costs would decrease by 6,3%. The significant increase of generation costs in the nodal and zonal cases with large amounts of renewable sources, together with the decrease of these in the copper plate case, encourages to conclude that this increase might be due to a shortage in network capacity that produces congestions and causes either more expensive technologies to be committed or demand to not be met, and hence non-served energy costs to rise. In fact, Table 4.1 shows the significant variations in non-served energy costs between the high and low renewable scenarios for the zonal and nodal power market designs. However, further analysis is performed in subsequent sections before reaching that conclusion.

Additionally, it can be noticed that the mentioned effect of an inappropriate network for a future scenario with high renewables is amplified in the nodal market, which has a slightly higher difference than in the zonal market (see Table 4.2). The reason for this lies in the inherent characteristic of the nodal market to optimally utilize the generating resources in the system across the entire system. Therefore, a poor network would distort the ideal functioning of the nodal market scheme.

Table 4.2. Comparison of total variable generation costs between Reference scenario (2014) and Vision 4 (2030) for the three proposed power market designs in all their phases.

Power Market Design	Reference scenario (2014) Low RES	Vision 4 (2030) High RES	Vision 4 vs. Reference scenario (%)
Copper Plate	1559,9	1462,3	-6,3
Nodal	1640,6	1882,8	14,8
Zonal First Phase	1640,5	1866,9	13,8
Zonal Redispatch Phase	1660,0	1888,9	13,8

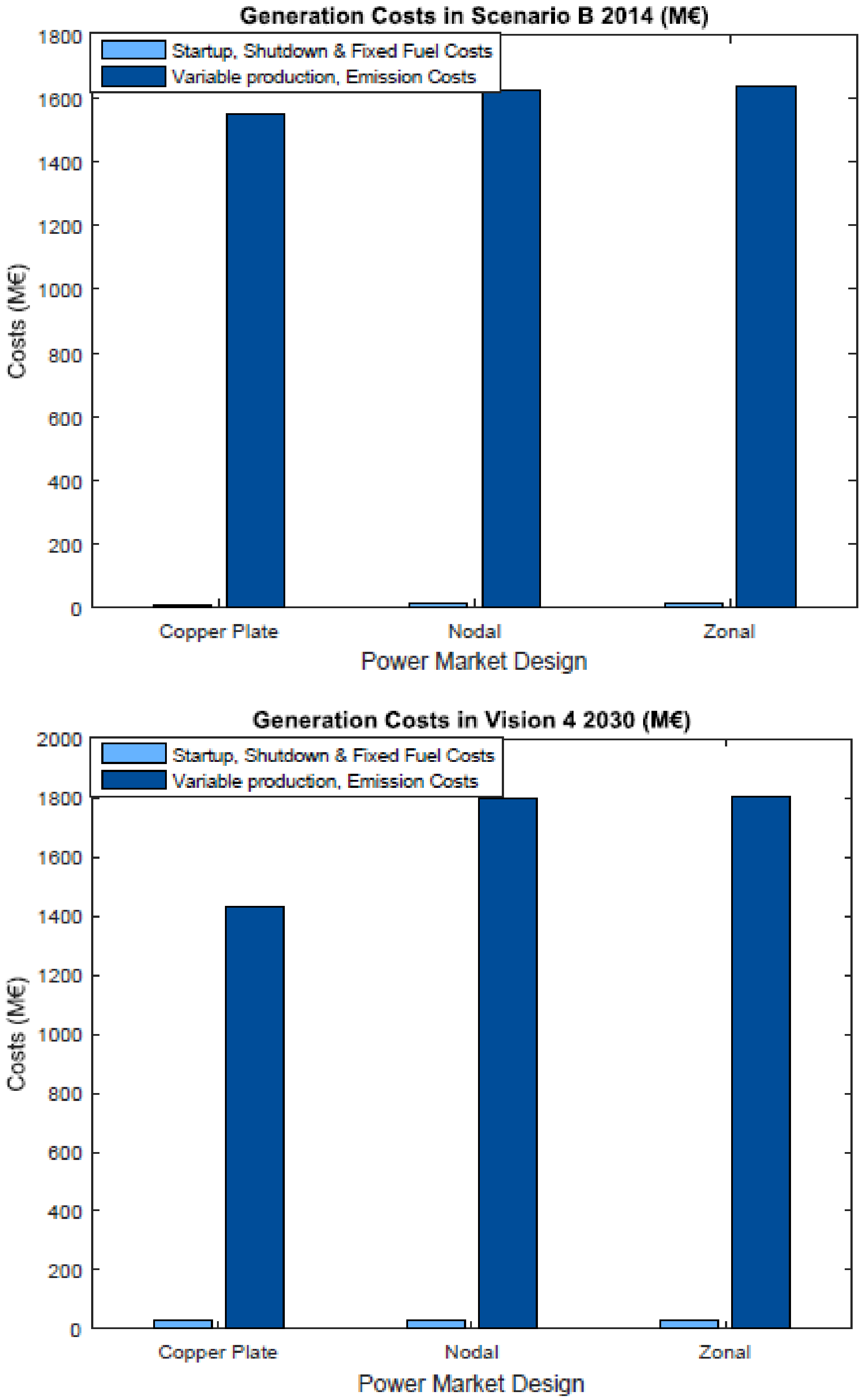

Figure 4.1. Generation costs in Reference scenario B (2014) and Vision 4 (2030).

In summary, the results referred to above reveal a potential saving of 0,32% in variable generation costs under nodal power market operation in contrast to a power system operating under a zonal market. Especially if the large expected projections of renewable sources of generation finally materializes, the result above could indicate that a nodal market in Europe would allow to maximize social welfare provided that the required network capacities are delivered effectively.

4.2. Further Analysis of RES Scenarios and Power Market Designs

The following subsections discuss some possible underlying causes of the increase in variable generation costs in a high renewable scenario. Several output variables are analyzed such as the curtailment of renewable generation, the total production of every type of technology and the non-served energy in the system.

Also, in this section the electricity prices calculated *a posteriori* in the model are presented and an analysis is done on how they might influence actors in the power sector and across regions in Europe.

4.2.1 Curtailment of renewable energy

As it was mentioned in section 2.4.2, renewable energy production is given priority in the day-ahead's merit order among the rest of generation technologies. However, it could happen that, due to the concentration of these energy sources in the end-points of the network and a weak transmission capacity in some specific parts of it, wind and solar power spillages not only become necessary but could turn out to be significantly high with larger integration of renewables. In a current zonal market total system generation costs would increase due to the redispatch process and revenues for renewable energy producers would shrink.

The outputs of the model show that the degree of curtailment rises notably in Vision 4 compared to the reference scenario, for which there is no curtailment. Figure 4.2 presents the distribution of the system's hourly curtailment, expressed in percentage and calculated with respect to the maximum renewable generation. For Vision 4, it can be observed that half of the hourly curtailment lies between approximately 1% and 9% in the nodal case and between 1% and 9,5% in the zonal case (the interquartile range in the box-plots). Therefore, in both power market designs the curtailment variability is very similar, with slightly higher maximum curtailment values, above 22%, in the zonal case.

The similarity between both system curtailment profiles can be largely attributed to using the same renewable daily patterns implicitly accounted for in the wind and solar feed-ins. The difference between them, however, results from the required redispatch process in the zonal market. This highlights again that provided the network capacities are limited, a nodal market proves to make a slightly more efficient use of the available transmission capacity and promotes a better integration of renewable energies. Nevertheless, further analysis should be made with different time horizons and other weeks during the year, since the one modeled could have been an exceptional one in terms of renewable generation.

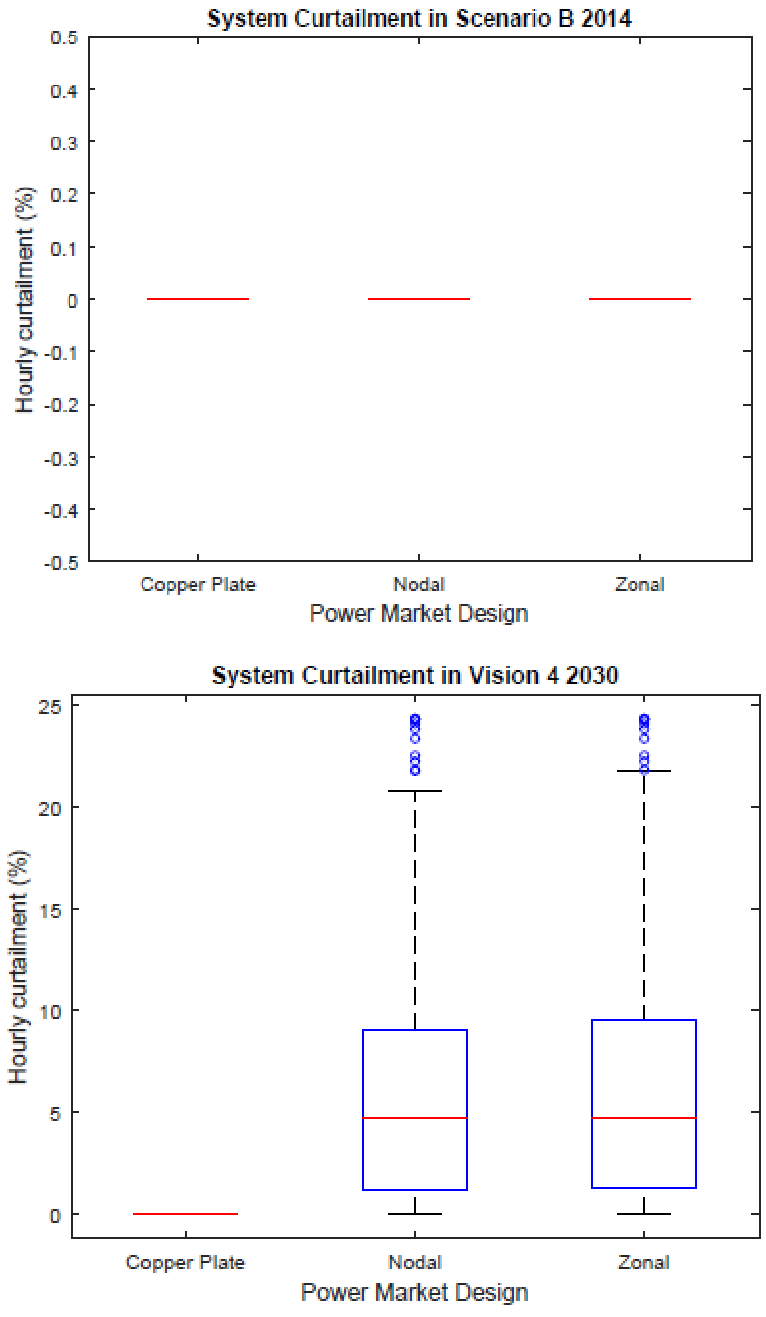

Figure 4.2. Distribution of the hourly RES curtailment of the power system in Reference scenario (2014) and Vision 4 (2030).

In absolute terms, in a power system that would generate a weekly amount close to 45,3 TWh of energy in a extreme high renewable scenario in 2030, around 1,57 TWh of renewable energy in the nodal case and 1,60 TWh in the zonal case would be "spilled". These amounts represent a weekly curtailment of 7,83% and 8,01%, respectively, with respect to the weekly renewable energy production (see Table 4.3). These curtailment values are noteworthy. A major reason that could justify such notable amounts of curtailment in the European system is the insufficient development of the transmission network assumed which leads to the incapability of supplying cheap renewable energy across wide regions and having to commit or reschedule local and more expensive technologies. In this research, no grid upgrades have been included between scenarios for comparison reasons. However, it is clear that network planning should keep the deployment of future renewables in mind and economic assessments should be performed to quantify the savings made with reduced curtailment against the expensive investments of line extensions.

Table 4.3. Renewable production, total production and curtailment of renewable energy in Reference scenario (2014) and Vision 4 (2030) for the three power market designs.

System output	Copper Plate	Nodal	Zonal Redispatch Phase
Vision 4, 2030 (High RES scenario)			
RES Production (GWh)	21599,89	20031,19	19998,35
Total generation (GWh)	45591,08	45327,10	45313,98
Curtailment (GWh)	0,00	1568,71	1601,54
Curtailment (%)	0,00	7,83	8,01
Reference scenario, 2014 (Low RES scenario)			
RES Production (GWh)	5646,03	5646,03	5646,03
Total generation (GWh)	36391,36	36382,58	36332,57
Curtailment (GWh)	0,00	0,00	0,00
Curtailment (%)	0,00	0,00	0,00

Besides the above, curtailment of renewables can also take place when an adequate reserves margin is required to maintain system balance and system reliability. Figure 4.3 shows that the time intervals in which system curtailment would be highest match with the early hours of the day during which the highest increase of demand occurs. Before this period coal, gas and fuel oil power plants are usually brought up to their technical minimum output and, hence, excess night wind power output needs to be turned off. In the next section an analysis will be done with regard to the dispatch generation profiles, and it then can be further analysed whether thermal generation substitutes renewables in such periods.

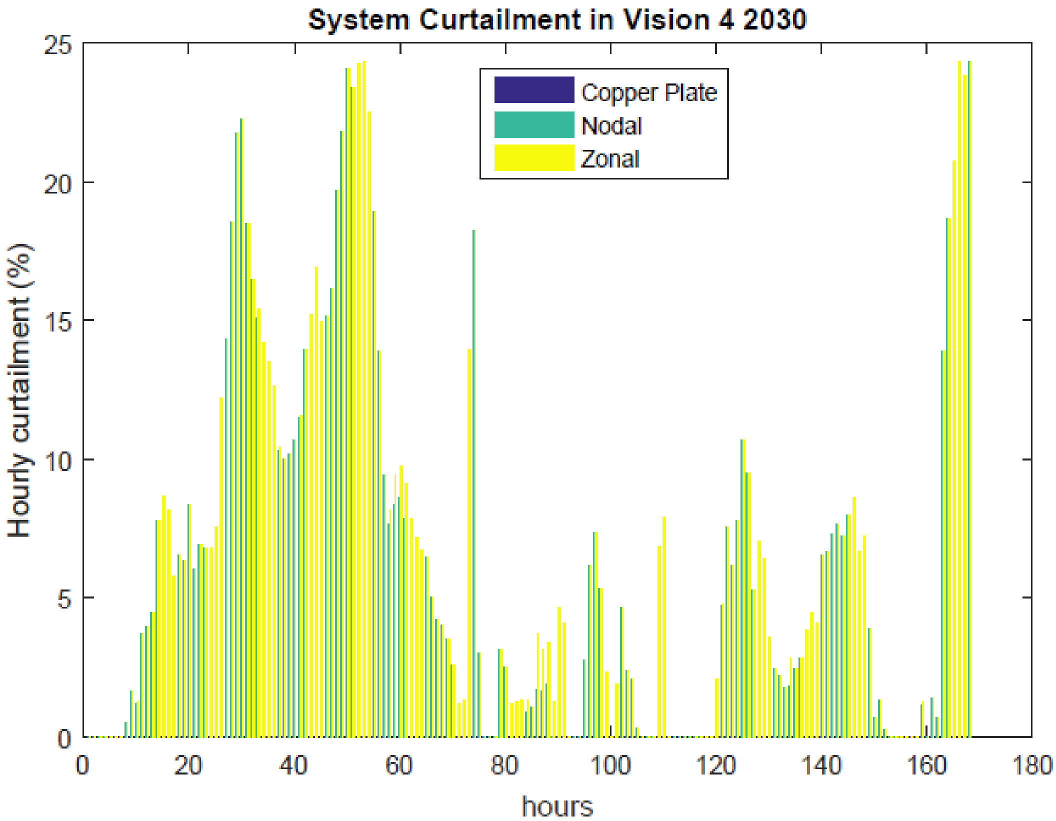

Figure 4.3. Hourly wind and solar energy curtailment in the power system in Vision 4 (2030).

Finally, curtailment can also occur due to a global oversupply in the system. In this situation, there is an excessive amount of generation capacity installed than what is actually needed. Such situation can be detected by checking whether there is demand systematically not met in every node in the network for consecutive hours. Section 4.2.3 looks further into this.

4.2.2 System Generation Dispatch profiles

This section looks into the generation dispatch profiles obtained for the system as a whole under the three different power market designs and for the low and high renewable scenario.

The reader should be reminded that Vision 4 assumes a strong integrated European market with harmonized policies within Member States, and this is reflected in the generation mix and in the capacities installed in the system of each type of technology. All energy resources should be available to meet demand everywhere else in Europe.

Compared to the reference scenario, in Vision 4 and in all three power market designs there is a significant reduction in nuclear power usage as base load mainly to accommodate the large amounts of renewables (see Figure 4.4). Moreover, the nuclear power generated in the high renewable scenario follows a more variable profile suggesting greater flexibility in the operation of nuclear power plants in the near future.

Regarding more flexible plants like coal-fired or gas-fired plants, these have undergone substantial changes in their dispatch pattern. Both technologies become even more flexible, experiencing drastic peaks and valleys in Vision 4. Overall, energy production from these two technologies has experienced inverted behaviours: gas-fired plants increased their production despite the high fuel costs in contrast to the reduction of coal-fired power plants production (see Table 4.4). The need for quick responsive backup technologies with high penetration of renewables and a high CO_2 emission cost rate used have led to this increase in usage. With respect to oil-fired plants, their energy output has reduced mainly to the reduction of their capacity installed across the continent.

Renewable energy production, however, has reached very high levels in Vision 4, to the extent that in some particular hours all the demand is covered with almost only nuclear and renewable energy especially in the Copper Plate market (see Figure 4.4).

When comparing between power market designs, Table 4.4 shows that nodal and zonal power markets, if yet different, are quite similar in contrast to the power outputs obtained in the copper plate option. On the one hand, larger amounts of cheaper energy, i.e. renewables and nuclear, are produced in the copper plate instead of using the more expensive thermal technologies. This partly explains the cheaper variable generation costs obtained in a theoretical copper plate system. On the other hand, in the nodal and zonal markets more production comes from gas (18,22% and 18,46%, respectively) and coal plants (30,01% and 30,66%, respectively) due to the limitations in the network and the redispatch process that prevent cost-efficient technologies from being dispatched.

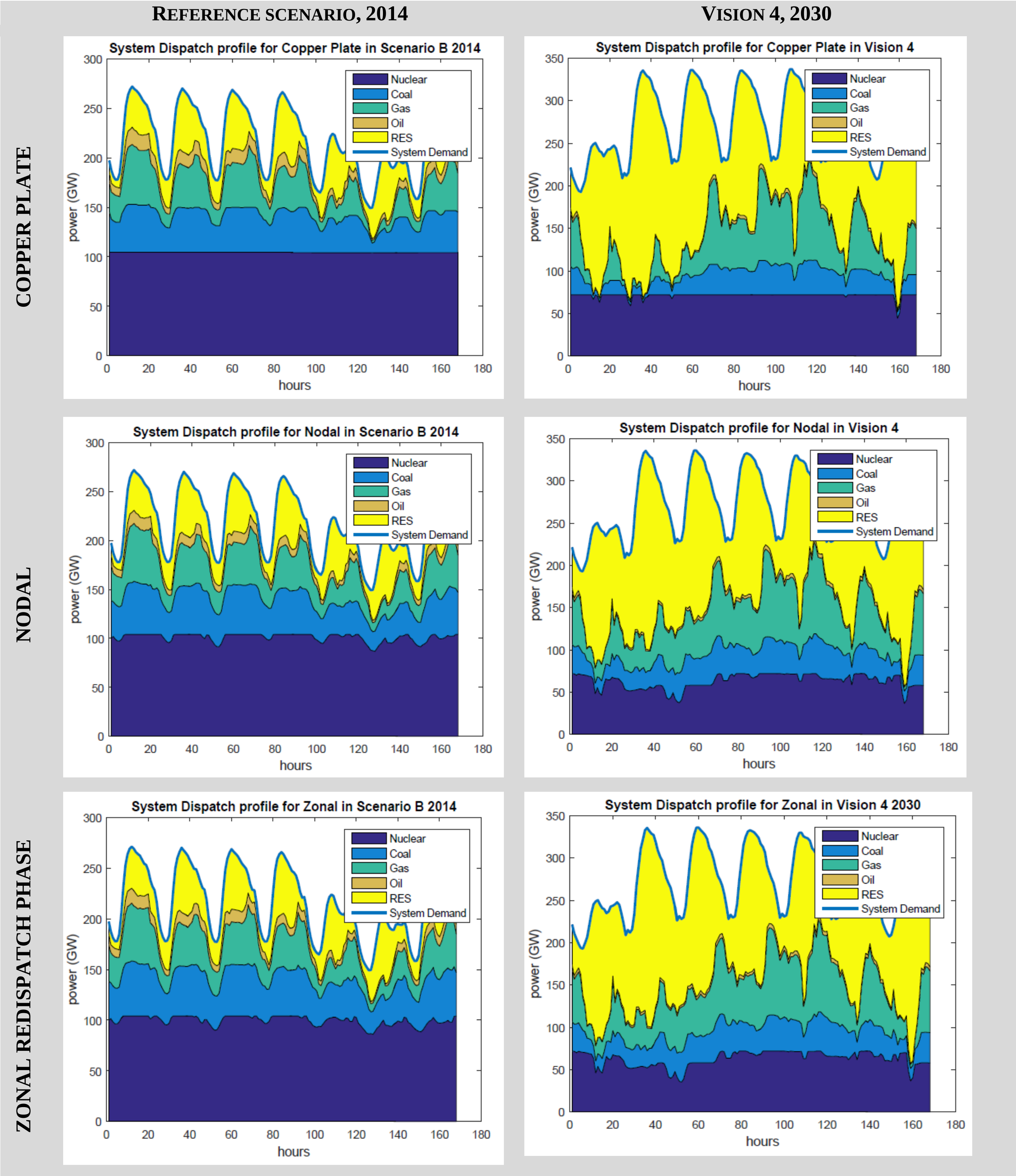

Figure 4.4. Generation dispatch profiles in Reference scenario (2014) and Vision 4 (2030) for the three power market designs

Table 4.4. Breakdown of energy production by technology type in Reference scenario (2014) and Vision 4 (2030) for the three power market designs.

Production by technology type (GWh)	Copper Plate	Nodal	Zonal Redispatch Phase	△ of Nodal with respect to Copper Plate (%)	△ of Zonal with respect to Copper Plate (%)
Vision 4, 2030 (High RES scenario)					
Gas	7528,04	8899,65	8917,84	18,22	18,46
Coal	4040,22	5252,62	5279,10	30,01	30,66
Nuclear	11968,85	10594,33	10557,51	-11,48	-11,79
Oil	454,07	549,32	561,18	20,98	23,59
RES	21599,89	20031,19	19998,35	-7,26	-7,41
Total	45591,08	45327,10	45313,98	-0,58	-0,61
Reference scenario, 2014 (Low RES scenario)					
Gas	5344,37	5769,47	5536,28	7,95	3,59
Coal	6246,18	6580,41	6970,96	5,35	11,60
Nuclear	17503,77	16996,99	16754,54	-2,90	-4,28
Oil	1651,02	1389,68	1424,76	-15,83	-13,70
RES	5646,03	5646,03	5646,03	0,00	0,00
Total	36391,36	36382,58	36332,57	-0,02	-0,16

If a further step is reached in the analysis and due attention is given to what is happening in the system's operating phases under a zonal power market, the reasoning by Neuhoff et al. (2011) is proved: zonal market produces an inefficient dispatch within countries.

The reason is again network limitations. After the first phase, a commitment schedule ignoring intra-zonal network limits, i.e. congestion, that ensures minimum system generation costs is obtained. The second phase takes care of the infeasibilities in the schedule caused by line congestions. This means that cheap generation that was aimed to supply a load center located somewhere in the network can no longer fulfill this due to the impossibility of being delivered. Instead, local and more expensive generation covers that shortage and the cheap generation i.e. renewable and nuclear energies face curtailments. As Table 4.5 shows, around 1,82% more gas and 1,82% more oil are dispatched in a high renewable scenario compared to the first phase. Similarly, nuclear and renewable plants are redispatched and their production decrease by 0,88% and 0,39%, respectively.

It is noteworthy to mention, however, that compared to a low renewable scenario the redispatch of expensive generation sources is reduced in relative terms, mainly due to the greater overall availability of renewable capacity installed in the system.

Table 4.5. Breakdown of energy production by technology type in Reference scenario (2014) and Vision 4 (2030) for zonal power market in its two phases.

Production by technology type (GWh)	First Phase (I)	Redispatch Phase (II)	△ of Redispatch phase with respect to First Phase (%)
Vision 4, 2030 (High RES scenario)			
Gas	8758,23	8917,84	1,82
Coal	5292,10	5279,10	-0,25
Nuclear	10650,72	10557,51	-0,88
Oil	551,16	561,18	1,82
RES	20077,06	19998,35	-0,39
Total	45329,28	45313,98	-0,03
Reference scenario, 2014 (Low RES scenario)			
Gas	5276,78	5536,28	4,92
Coal	6962,33	6970,96	0,12
Nuclear	17132,04	16754,54	-2,20
Oil	1368,64	1424,76	4,10
RES	5646,03	5646,03	0,00
Total	36385,82	36332,57	-0,15

On the one hand, these results reveal that managing national congestion during the operational hour, after market clearance i.e. after a unit commitment schedule is generated, rather than through the market, as it is done under a nodal scheme, it ultimately produces higher generation costs especially when the network transmission capacities are designed so that small levels of congestion are always produced. On the other hand, the increased amount in renewable generation in the high RES scenario produces variations in the merit order dispatch with respect to that of the reference scenario, which in turn highlights the changes undergone with each market design as well as the slight differences between them.

4.2.3 Non-served energy

This section analyses to what extent the non-served energy costs impact on the system's dispatch and on the system's variable generation costs in the different power market designs and in the high and low renewable scenarios.

As previously stated in section 4.1, the magnitude of the non-served energy costs are considerably high for the nodal and zonal markets in a scenario with high penetration of renewable energies. Costs of unserved energy in the zonal market amount to 58,22 Million Euros, a 4,72% larger than those in the nodal market, 55,60 Million Euros (see Table 4.6). In the reference scenario, however, non-served energy costs only amount to 1,88 Million Euros in the nodal market and to 11,9 Million Euros in the zonal market. The latter one is still considerably high.

Table 4.6. Comparison of non-served energy costs between Reference scenario (2014) and Vision 4 (2030) for the three proposed power market designs in all their phases.

Costs (in Million Euros)	Copper Plate	Nodal	Zonal Phase I	Zonal Phase I vs. Nodal (%)	Zonal Redispatch Phase	Zonal Redispatch Phase vs. Nodal (%)
Vision 4 (High RES scenario)						
Total Variable Generation	1462,35	1882,82	1866,85	-0,85	1888,90	0,32
Non-served energy	2,80	55,60	55,16	-0,78	58,22	4,72
Non-served energy **:** Total Variable Generation (%)	0,192	2,953	2,955		3,082	
Scenario B 2014 (Low RES scenario)						
Total Variable Generation	1559,94	1640,65	1640,53	-0,01	1659,9	1,17
Non-served energy	0,12	1,88	1,96	4,74	11,9	531,66
Non-served energy **:** Total Variable Generation (%)	0,008	0,114	0,120		0,717	

These costs largely depend on the system's generation adequacy to meet the required demand, reflected by the costs in a Copper Plate market in Table 4.6, and the system's network capacity planning to appropriately deliver the energy to all demand points in the network. Non-served energy costs of nodal and zonal markets represent 2,95% and 3,08% of the total system's variable generation costs, respectively (see Table 4.6). It is again highlighted the importance of a timely delivery of the network infrastructure investments in order to gradually integrate the large deployment of renewables in the system.

4.2.4 Effects of system outputs on the generation costs

In the subsections above, it has been discussed the influence of a large penetration of renewable energies in the power system and the design of the latter on the following system outputs: curtailment of renewable energy, system's economic generation dispatch profile and non-served energy in the system.

As a summary, Table 4.7 shows the contribution of the system outputs on the system's variable generation costs. It should be noted that while the energy production by type of technology and the non-served energy directly impact on the costs of generation in the system, the curtailment of renewable energy does not directly contribute to it. The degree of curtailment of renewables instead shows the lost savings in the system's generation dispatch, the opportunity cost of having to spill renewable generation because of not having the sufficient physical network to deliver that green cheap energy.

Table 4.7. Impact of system outputs on variable generation costs.

System output (GWh)	Copper Plate	Nodal	Zonal Redispatch Phase	△ of Nodal with respect to Copper Plate (%)	△ of Zonal with respect to Copper Plate (%)
Vision 4, 2030 (High RES scenario)					
Gas	7528,04	8899,65	8917,84	18,22	18,46
Coal	4040,22	5252,62	5279,10	30,01	30,66
Nuclear	11968,85	10594,33	10557,51	-11,48	-11,79
Oil	454,07	549,32	561,18	20,98	23,59
RES	21599,89	20031,19	19998,35	-7,26	-7,41
Non-served energy	14,01	277,99	291,11	1884,23	1977,82
Curtailment	0,00	1568,71	1601,54	Very large	Very large
Reference scenario, 2014 (Low RES scenario)					
Gas	5344,37	5769,47	5536,28	7,95	3,59
Coal	6246,18	6580,41	6970,96	5,35	11,60
Nuclear	17503,77	16996,99	16754,54	-2,90	-4,28
Oil	1651,02	1389,68	1424,76	-15,83	-13,70
RES	5646,03	5646,03	5646,03	0,00	0,00
Non-served energy	0,60	9,38	59,39	1461,51	9785,13
Curtailment	0,00	0,00	0,00	0,00	0,00

Overall, a combination of factors leads to having higher variable generation costs in a scenario with high penetration of renewable technologies, as presented in section 4.1. As indicated in Table 4.7, a drastic increase of renewable production would contribute to a significant decrease in generation costs but a significant increase in gas production to support the unpredictability of renewables and maintain the system's reliability within adequate limits has the opposite impact. Simultaneously, around a 60% decrease in cheap nuclear production accentuates this effect even more. Furthermore, the high renewable scenario results in very large amounts of non-served energy due mainly to insufficient network capacity and large amounts of curtailment due again to congestions, i.e. network inadequacy, that prevent cheap renewable energy to be transported to load centers far away.

With respect to the power market designs, and taking Copper Plate as a reference, the nodal and zonal markets experiment higher amounts of gas, coal and oil, i.e. more expensive technologies, and a reduction in nuclear and renewable energy productions. As for non-served energy and curtailment levels, these are extremely above those of the Copper Plate market (see Table 4.7). Additionally, it should be mentioned that, in a high renewable scenario, nodal and zonal markets have very close percentage differences between them for every system output, when compared to Copper Plate. Finally, and referring back to the second research sub-question, it all comes down to having an adequate planning to expand the network and be able to follow up a complete integration of electricity markets and the deployment of the renewable targets. Therefore, whether it makes operational and economical sense to implement a nodal market in Europe will depend on the network expansion projects and the success of cooperation policies between Member States.

4.2.5 Electricity Prices and Congestion Costs

This section presents an overview of the electricity prices calculated following the model's economic dispatch outcome. More specifically, the weekly average electricity prices in the nodal and zonal markets and the difference between them are presented for both high and low renewable scenarios.

Wholesale electricity prices under a nodal market scheme bring many short-term benefits as already identified in previous sections. They provide more transparency to market players, more efficiency and reliability in system operation for TSOs at the same time they reduce local market power practices and unwanted trading strategies, the so-called "inc-dec game" (Neuhoff, et al., 2011) and support the transmission planning process. Moreover, demand responsiveness would also benefit from its implementation in retail markets.

Figure 4.5 indeed reveals an overall decreasing trend in weekly average nodal prices in a higher renewable scenario in both market designs. Furthermore, in the case of the nodal market both intra-national and cross-border network congestions can be observed in the reference scenario between some regions: between North and South of Germany, between Czech Republic and Germany, between France and Germany, between Belgium and France or within Belgium. This suggests the need for transmission capacity development both within national power grids and between international borders. Also, these congestions, especially in continental Europe, seem to be alleviated with the presence of more renewables. Most probably this is due to the higher amounts of renewable generation that meet the demand in every node of the network. Nonetheless, congestions keep existing between the end points of the network and continental Europe.

In the case of the zonal market, the nodal prices reflect the single electricity price per zone, i.e. per country, and as it can be observed in Figure 4.5 there is also a tendency towards greater homogenization of prices with larger amounts of renewable energies, especially in central-western Europe. The extremes of the network, however, have either much cheaper electricity prices due probably to a higher concentration of renewable sources or much more expensive prices. The latter could be due to either a lack of transmission capacity or a still quite predominant thermal generation mix, like the case of Poland, in which prices are pushed upwards through the merit order mechanism.

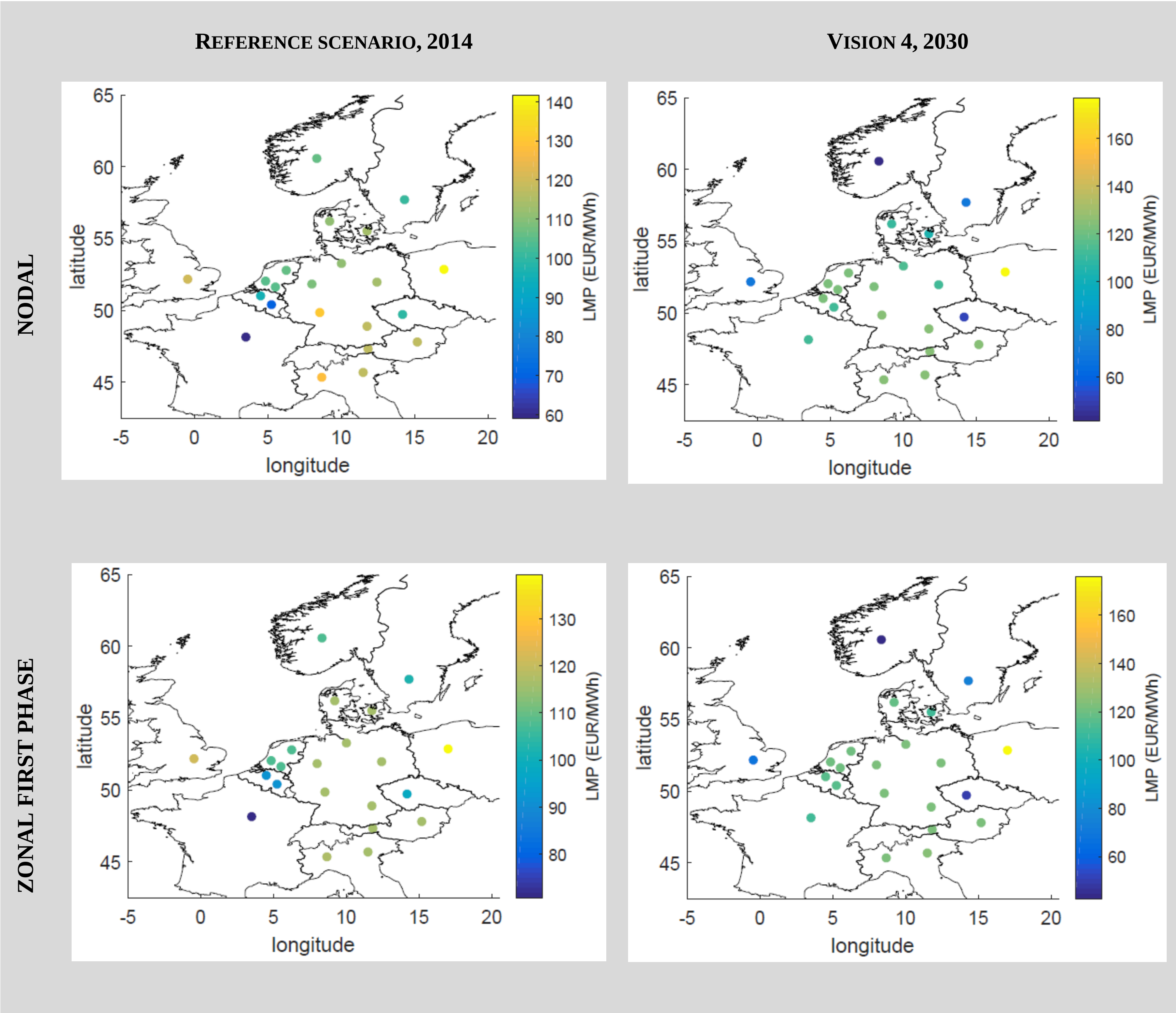

Figure 4.5. Average Locational Marginal Prices in nodal and zonal markets in Reference scenario (2014) and Vision 4 (2030).

Through the operational information given in real-time by TSOs, including the information about the state of the network provided by the LMPs, generators can identify when and where congestions and supply shortages are taking place allowing them to consider it in their short-term decision-making. From the consumer's point of view, however, only those that explicitly bid into the wholesale market are directly impacted by the prices. The rest of consumers who are supplied by electric utilities do not experiment the full impact of the LMPs and their variations for now, since utilities average prices across the territories where they own generating units. Only competitive retail markets that facilitate demand response initiatives would give the opportunity to consumers to react to price spikes.

In order to check for differences in LMPs between power market designs and how these might affect participants in the European power market, Figure 4.6 plots the difference between weekly average nodal prices under both market designs, calculated as: $\triangle LMP = LMP_{zonal} - LMP_{nodal}$.

Overall, the differences between nodal prices, if already small, are generally even smaller in a higher renewable scenario, as shown in Figure 4.6. Moreover, energy producers get paid at the node where their generators are located. Therefore generators located in zones like the south of Germany, Netherlands, Austria and north of Italy, for instance, where the differences in LMPs are negative, would benefit from the implementation of a nodal market scheme since LMPs in nodal would be higher than those in a zonal market. Figure 4.6, in fact, illustrates that implementing a nodal market in Europe would impact to a greater or lesser extent on the revenues of the energy producers across the continent, both within national borders and outside a country's borders. This result suggests that a harmonization of the energy policies related to capacity markets is necessary in the different Member States to minimize welfare redistributions issues.

However, it should be taken into account, though, that the modeled week could be an anomalous one in terms of renewable generation for example. Therefore, a more in-depth analysis of the electricity prices is needed to conclude the degree of impact of the market design and the large amounts of intermittent generation on the LMPs and therefore on the market actors. The price analysis should be done for a longer time horizon and in different seasons of the year.

REFERENCE SCENARIO, 2014 **VISION 4, 2030**

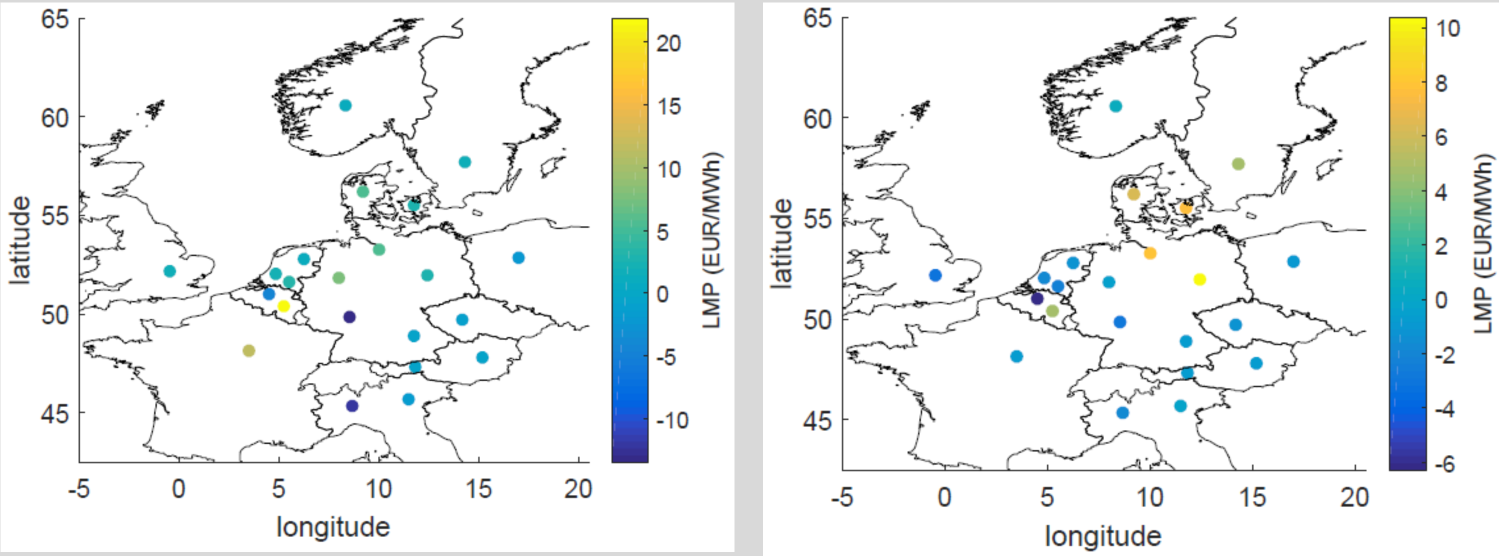

Figure 4.6. Difference in average Locational Marginal Prices between nodal and zonal markets in Reference scenario (2014) and Vision 4 (2030).

4.2.6 Sensitivity analysis of model parameters

In the following subsections a sensitivity analysis is performed to test the impact of the CO_2 emission cost rate and the intra-zonal network capacities on the outcomes of the model, mainly on the system variable generation costs, the economic dispatch profiles and the nodal prices under the nodal and zonal market designs. The sensitivity analysis is performed for the high renewable scenario and it is contrasted against that of the base case.

4.2.6.1. CO_2 emission cost rate

The base case value for the CO_2 emission cost rate was set to 100€/tonnes of CO_2, which is thought to be on the high side of the forecasting range. Therefore, a significantly lower value of 20€/ tonnes of CO_2 is chosen for the sensitivity analysis.

As Table 4.8 shows, with a CO_2 cost five times lower, total variable generation costs in a high renewable scenario would be 0,58% higher in a zonal market with respect to a nodal market, in contrast to the 0,32% difference in the base case (see Table 4.1). Besides, operation costs are lower as cheaper coal generation is dispatched instead of expensive gas units. Figure 4.7 indeed shows that part of the base case gas production has been replaced by production of coal.

Table 4.8. Breakdown of generation, non-served energy and redispatch costs in Vision 4 (2030) for the nodal and zonal power markets and for the base case and low CO_2 emission cost rate.

Costs (Million Euros)	Nodal	Zonal Phase I	Zonal Phase I vs. Nodal (%)	Zonal Redispatch Phase	Zonal Redispatch Phase vs. Nodal (%)
Low CO_2 emission cost rate = 20 €/tonnes of CO_2					
Total Variable Generation	1106,9	1090,2	-1,5	1113,3	0,58
Fixed Generation	28,4	29,4	3,5	29,4	3,50
Operation	1055,7	1038,8	-1,6	1054,9	-0,08
Non-served energy	22,7	22,0	-3,1	29,0	27,69
Redispatch	-	-		16,1	
Base case					
Total Variable Generation	1882,8	1866,9	-0,8	1888,9	0,32
Fixed Generation	28,6	28,0	-2,3	28,0	-2,30
Operation	1798,6	1783,7	-0,8	1802,7	0,23
Non-served energy	55,6	55,2	-0,8	58,2	4,72
Redispatch	-	-		19,0	

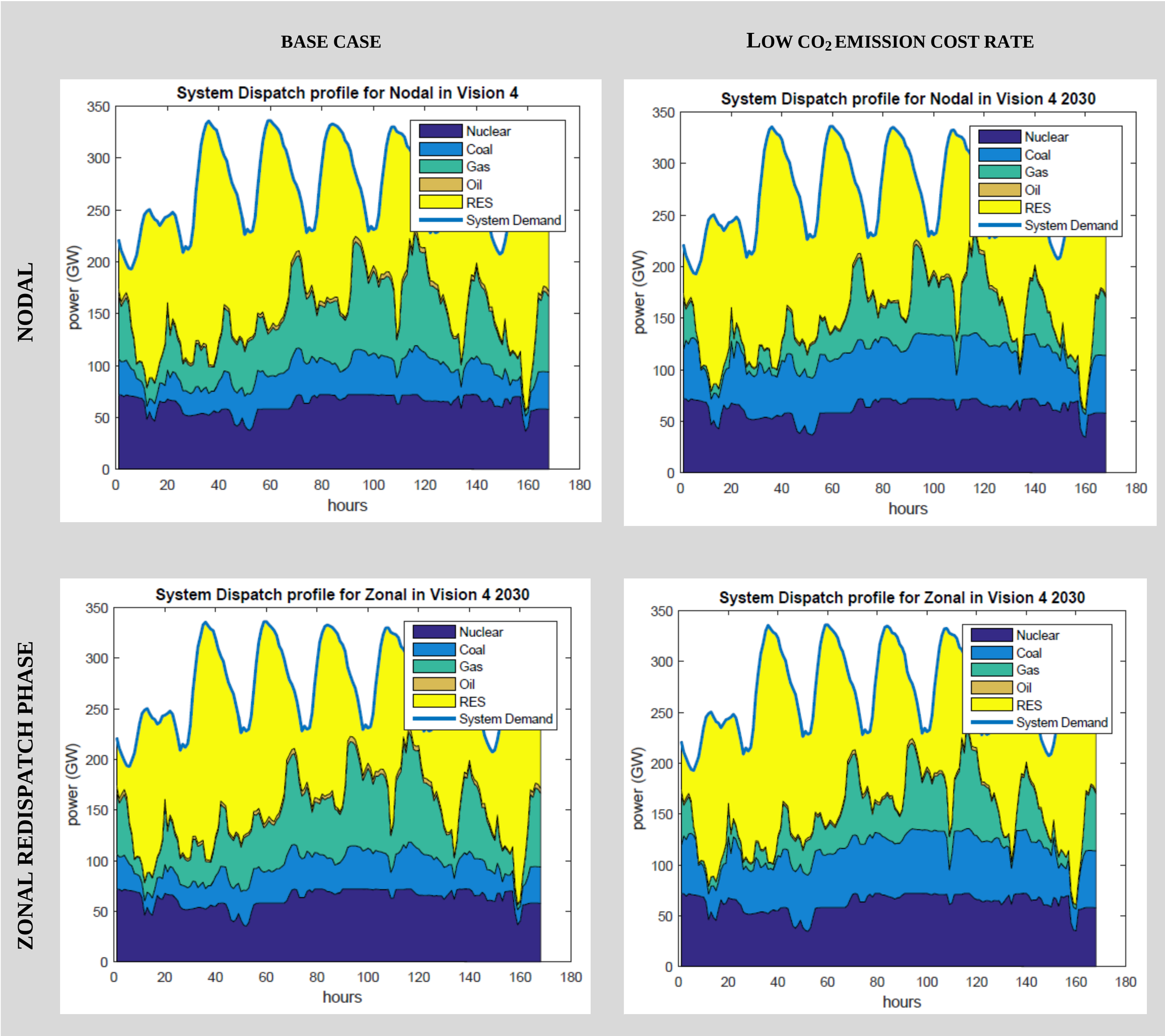

Figure 4.7. Generation dispatch profiles in Vision 4 (2030) for the nodal and zonal power market designs for the base case and low CO2 emission cost rate.

With regard to the nodal prices of electricity, while a lower CO_2 emission cost does not influence to a large degree, in principle, the network's congestion patterns, Figure 4.8 does show reduced nodal prices in both market designs with a lower CO_2 price. From the policy perspective, this underlines the importance of setting appropriate tax levels or subsidies that could otherwise distort the market outcome to undesirable levels.

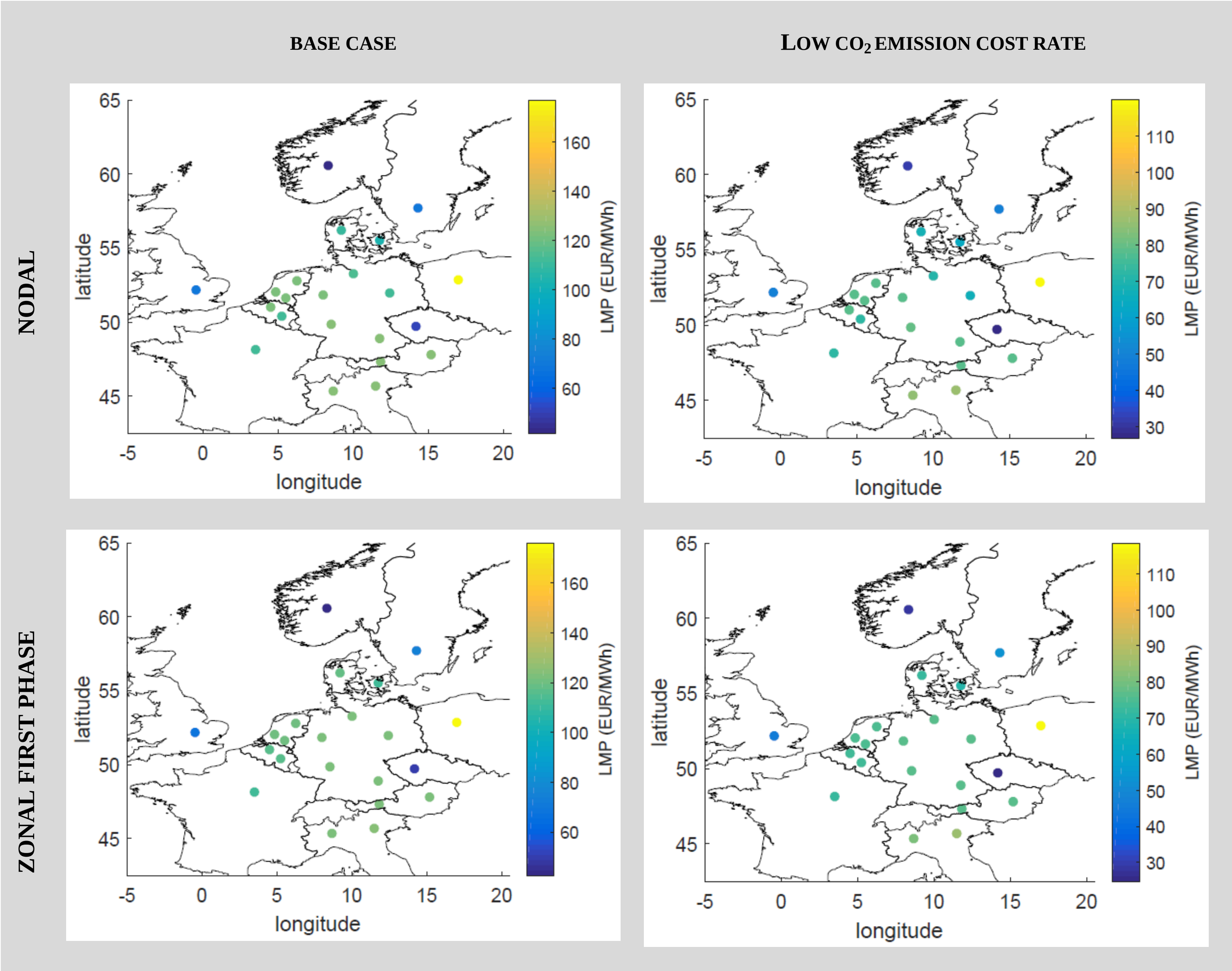

Figure 4.8. Average Locational Marginal Prices in Vision 4 (2030) for the nodal and zonal markets for the base case and low CO2 emission cost rate.

A lower CO_2 price also makes the difference between the electricity prices in the zonal and nodal markets more negative across the network (see Figure 4.9), thus, favouring the nodal market in the generators' view as revenues would be larger. However, some zones in northern

Germany and Denmark would still slightly benefit from a zonal market. Again, a broader price analysis should be performed to be able to conclude more firmly.

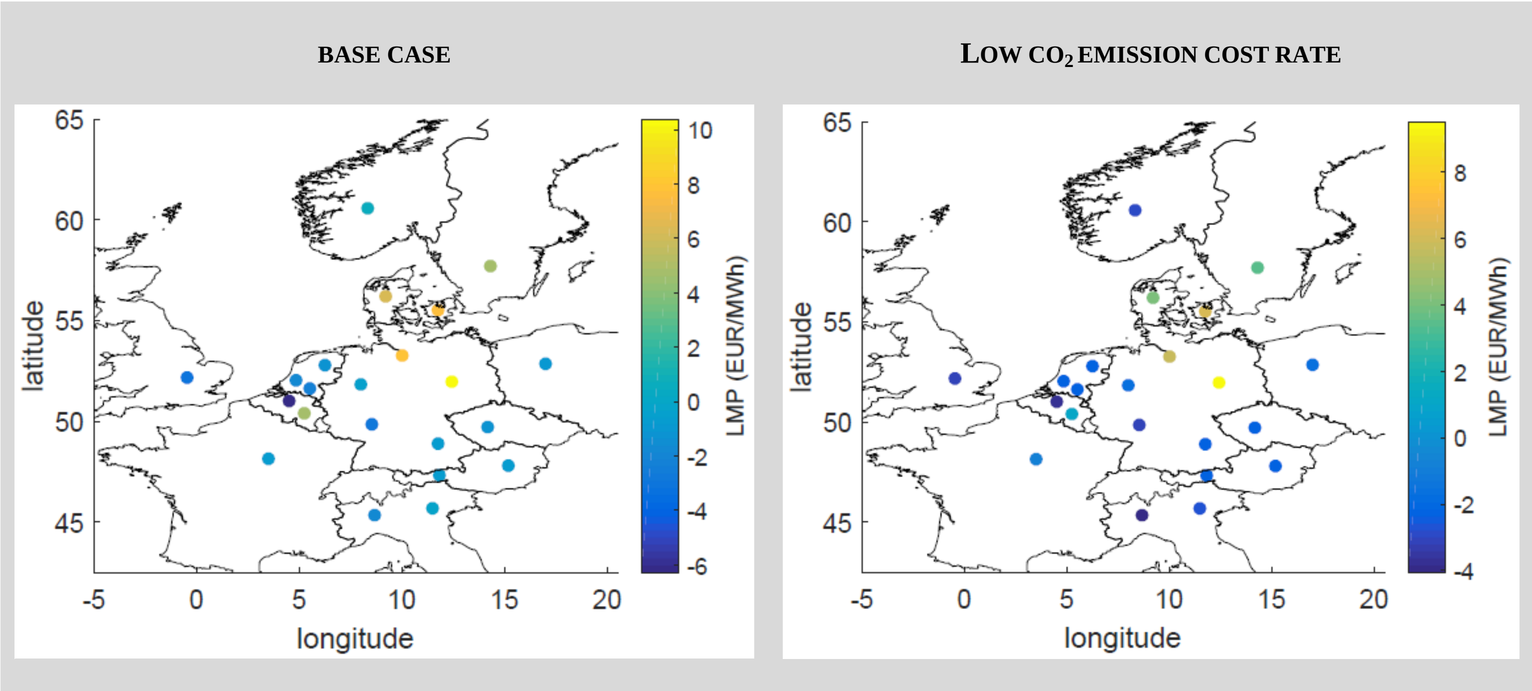

Figure 4.9. Difference in average Locational Marginal Prices between nodal and zonal markets in Vision 4 (2030) for the base case and low CO2 emission cost rate.

4.2.6.2. Intra-zonal network capacities

Transmission lines and network capacities represent important factors in the modeling of the power system since they determine the power flow profiles and the power limits of the lines. Two sensitivity tests will be performed to analyse the impact of doubling or halving intra-zonal capacities on system variable generation costs, on nodal prices and on the difference of nodal prices between nodal and zonal markets. The intra-zonal network capacities are the line capacities located within a country.

4.2.6.2.1. Double intra-zonal network capacities

Increasing by 50% the capacities of the intra-zonal transmission lines would reduce the difference in total variable generation costs between the nodal and zonal markets to 0,17% as compared to the 0,32% of the base case (see Table 4.9). However, a 4,38% difference in non-served energy costs between zonal and nodal markets is still close to that of the base case, 4,72%. Plus, absolute values of non-served energy costs are very similar to those in the base case. Moreover, total variable generation costs would be reduced by only 0,5% and 0,65%, in the nodal and zonal markets respectively, compared to the base case. This suggests that doubling the capacities within zones would not be enough to meet system's demand in a cost-efficient way.

Table 4.9. Breakdown of generation, non-served energy and redispatch costs in Vision 4 (2030) for the nodal and zonal power markets and for the base case and double intra-zonal capacities.

Costs (Million Euros)	Nodal	Zonal Phase I	Zonal Phase I vs. Nodal (%)	Zonal Redispatch Phase	Zonal Redispatch Phase vs. Nodal (%)
Double intra-zonal network capacities					
Total Variable Generation	1873,4	1866,9	-0,4	1876,6	0,17
Fixed Generation	28,9	28,0	-3,3	28,0	-3,32
Operation	1789,1	1783,7	-0,3	1790,9	0,10
Non-served energy	55,4	55,2	-0,4	57,8	4,38
Redispatch	-	-		7,1	
Base case					
Total Variable Generation	1882,8	1866,9	-0,8	1888,9	0,32
Fixed Generation	28,6	28,0	-2,3	28,0	-2,30
Operation	1798,6	1783,7	-0,8	1802,7	0,23
Non-served energy	55,6	55,2	-0,8	58,2	4,72
Redispatch	-	-		19,0	

In terms of alleviating network congestions, doubling the capacities within countries has slightly helped to improve transmission constraints in the nodal market between the north and south of Germany and within Belgium, as Figure 4.10 shows. Additionally, prices in the nodal market are very similar to those in the zonal market. Nevertheless, cross-border congestions limit the nodal market's potential to improve operating efficiency of the system since they keep being quite significant.

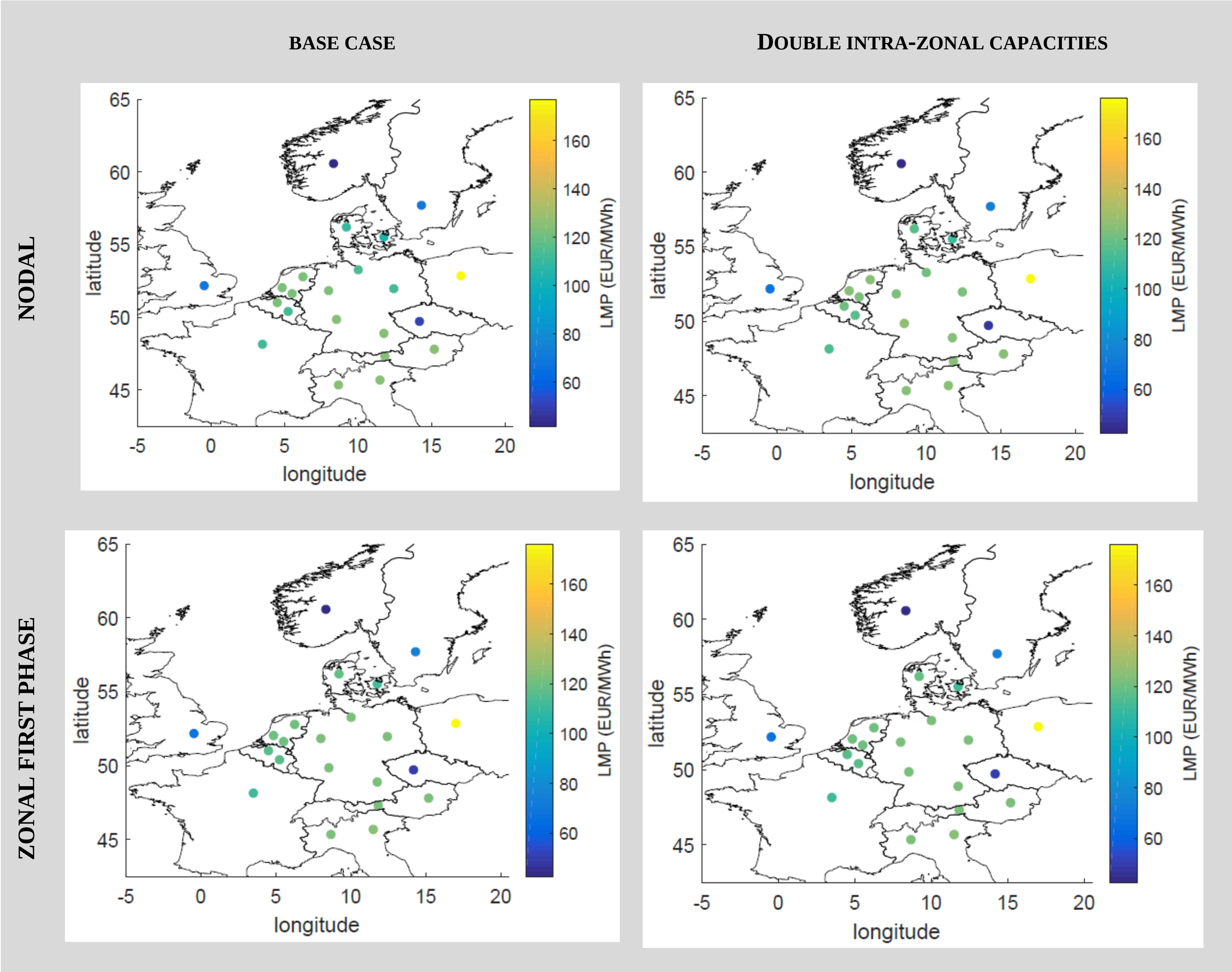

Figure 4.10. Average Locational Marginal Prices in Vision 4 (2030) for the nodal and zonal markets for the base case and double intra-zonal capacities.

On the other hand, a 50% increase in the intra-zonal network capacities decrease the difference in nodal prices between both markets, compared to the base case, to values that range from -4 to 2 €/MWh according to Figure 4.11. From the generators' point of view, the small differences would hardly impact on their revenues if a nodal market is implemented. However, a more extensive study should be done in order to account for possible anomalies in this week's generation profile.

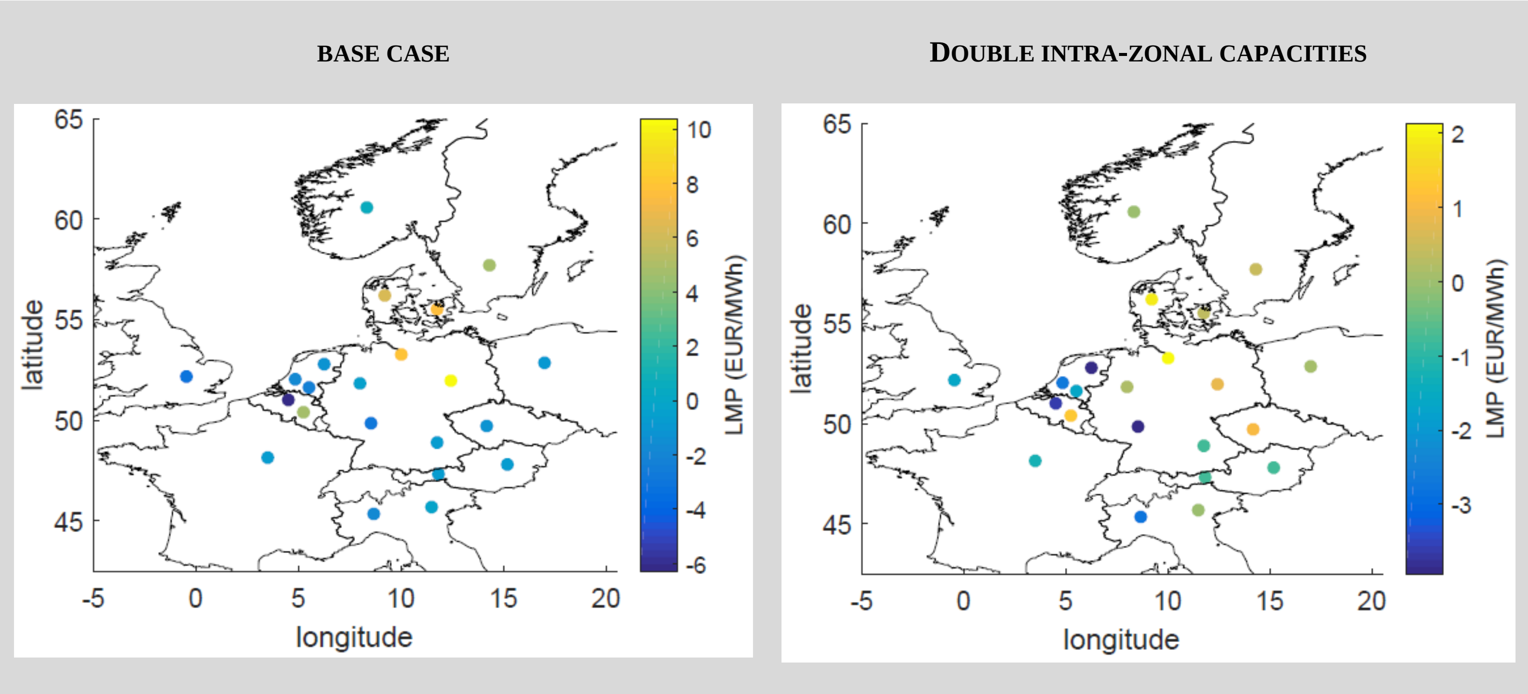

Figure 4.11. Difference in average Locational Marginal Prices between nodal and zonal markets in Vision 4 (2030) for the base case and double intra-zonal capacities.

4.2.6.2.2. Half intra-zonal network capacities

In the case of decreasing by 50% the intra-zonal capacities, the zonal market turns out to be 1,89% more costly in terms of total variable generation costs than the nodal market design. In comparison to the base case, total variable generation costs would be 3,36% higher in the nodal market and almost 5% higher in the zonal market. Moreover, in this case the redispatch costs would amount to 53,6 Million Euros, 2,82 times higher than in the base case, and non-served energy costs in the zonal redispatch phase would more than double those in the first phase, reaching 117,7 Million Euros (see Table 4.10).

Table 4.10. Breakdown of generation, non-served energy and redispatch costs in Vision 4 (2030) for the nodal and zonal power markets and for the base case and half intra-zonal capacities.

Costs (Million Euros)	Nodal	Zonal Phase I	Zonal Phase I vs. Nodal (%)	Zonal Redispatch Phase	Zonal Redispatch Phase vs. Nodal (%)
Half intra-zonal network capacities					
Total Variable Generation	1946,2	1866,9	-4,1	1983,1	1,89
Fixed Generation	28,4	28,0	-1,7	28,0	-1,66
Operation	1860,2	1783,7	-4,1	1837,4	-1,23
Non-served energy	57,5	55,2	-4,1	117,7	104,63
Redispatch	-	-		53,6	
Base case					
Total Variable Generation	1882,8	1866,9	-0,8	1888,9	0,32
Fixed Generation	28,6	28,0	-2,3	28,0	-2,30
Operation	1798,6	1783,7	-0,8	1802,7	0,23
Non-served energy	55,6	55,2	-0,8	58,2	4,72
Redispatch	-	-		19,0	

In relation to the electricity prices, reducing intra-zonal line capacities accentuates network congestions within zones even more. This can be observed in north-eastern Germany and Belgium in the nodal market, whereas in the zonal case no major change can be seen (Figure 4.12). Cross-border transmission constraints are again not affected. Here, it is reflected the transparency of the nodal market over the zonal one. The nodal market provides information about where transmission development would be more valuable to reduce congestions in the network while the zonal approach conceals it completely.

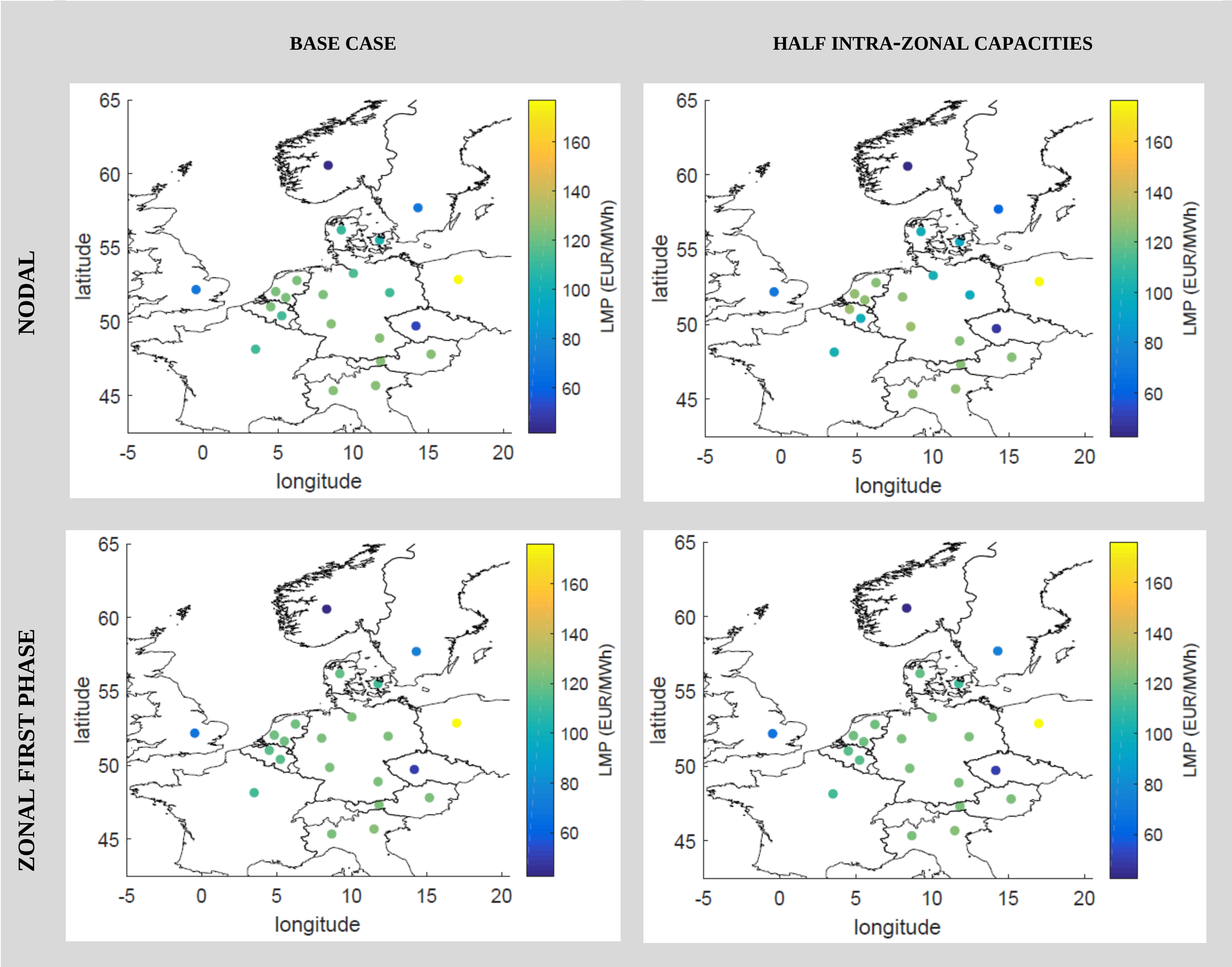

Figure 4.12. Average Locational Marginal Prices in Vision 4 (2030) for the nodal and zonal markets for the base case and half intra-zonal capacities.

Once again, in this case a 50% decrease in intra-zonal line capacities increase the differences between nodal prices of both markets to values ranging from -10 to 25 €/MWh (Figure 4.13). These magnitudes, yet low, could start to impact producers' behaviours in the market. Energy producers owning generators in nodes with a positive difference, meaning $LMP_{zonal} > LMP_{nodal}$, would rather operate under a zonal market structure, especially if those generators are downstream of a transmission constraint since that would mean that once the congestion is solved the price at that particular node will rise, hence increasing the generators' revenues.

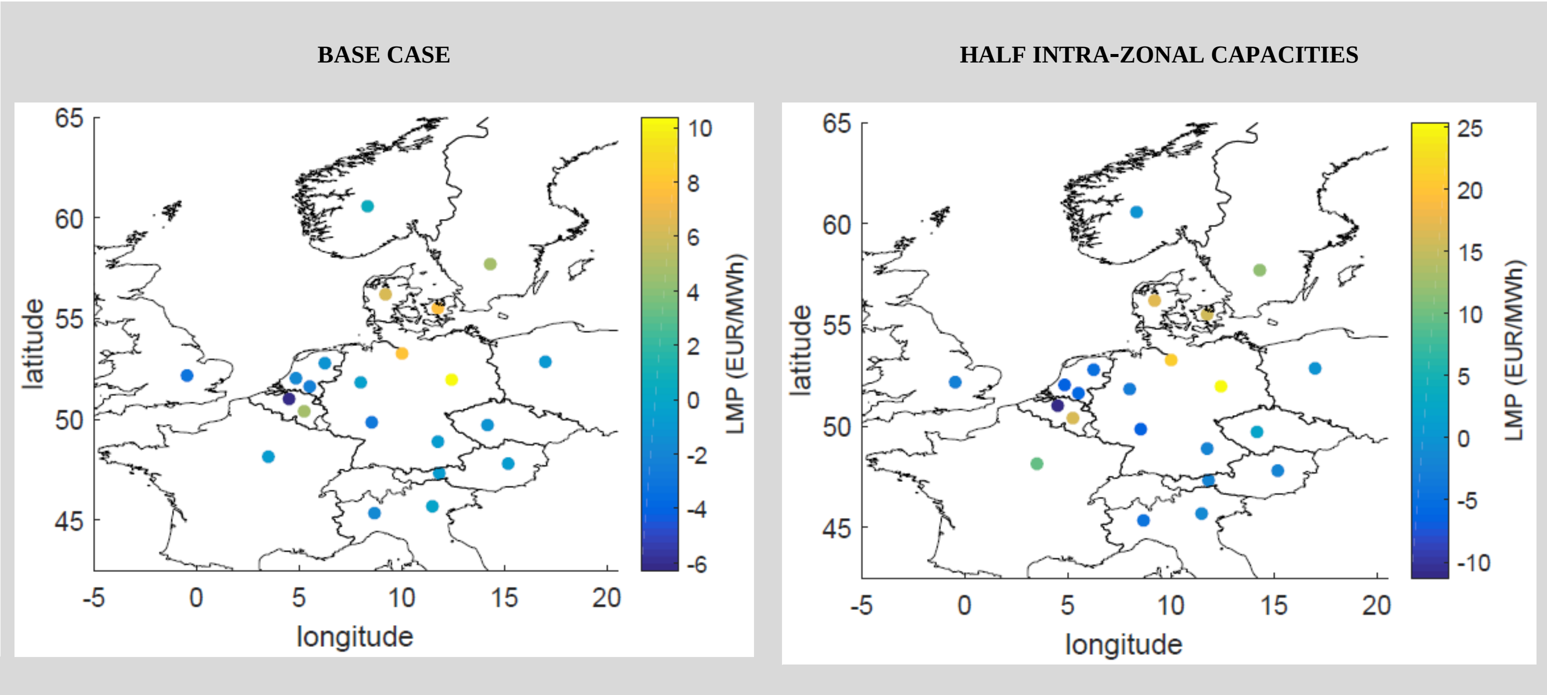

Figure 4.13. Difference in average Locational Marginal Prices between nodal and zonal markets in Vision 4 (2030) for the base case and half intra-zonal capacities.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

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5. Conclusions and Recommendations

In this last chapter the main results and conclusions drawn from the research work are presented. Section 5.1 formulates the answers to the main research question introduced in chapter 1 as well as to its three sub-questions. Section 5.2 reflects on the modeling process with the research work. Section 5.3 gives some recommendations for future research and relevant considerations for policy makers in the European power sector. Some final reflections on these policies are also exposed.

5.1. Conclusions of the research

This research work started with the objective of gaining better insights on the functioning of the European power sector and market under different power market designs and in high renewable scenarios. In particular, the main research question posed is:

To what extent can the power market design and the future expected large-scale integration of renewable energy sources have an effect on the system's variable generation costs of electricity?

High penetration of renewable energy sources bring a number of opportunities to many actors in the power system but involve also many big challenges to power system operators. Given their unpredictable nature and the need of a reliable and continuous system balance, the dispatch of large amounts of this green technology in combination with other existing conventional technologies will unfold new ways of operating the power market, starting by identifying the future transmission line congestions in the network. A power market design able to intrinsically manage congestion not only will play a positive effect on the integration of renewable energy sources but will also ensure the operation of the system at minimum costs.

The current power market rules in Europe respond to a multi-region day-ahead market coupling design (zonal market) in which real-time markets take into account inter-zonal congestion but establish a single electricity price inside each zone, namely a country. On a second phase, this is during operational hour, network congestion is handled by the Transmission System Operator (TSO) who conveniently redispatches generating units, incurring in extra operational costs. In a locational marginal pricing market scheme (nodal market), however, real-time markets determine the feasible generating schedule at one go and electricity prices internalize the locational value of delivering the energy, providing actors with a more transparent and efficient market design. The implementation of a nodal market design in Europe could lead to a potential saving of 0,32% in the system's total variable generation costs with respect to the zonal power market option.

A successful implementation of the power market's redesign also depends on an appropriate network expansion plan. The research has shown that a well-developed network infrastructure is a crucial factor in the effective integration of large amounts of renewable energies. The mentioned expansion plan should cover both already existing transmission lines that need reinforcements within and between regions and new ones that will become necessary when more off-shore wind farms are developed. An extended network could emphasize to a greater extent the 0,32% savings in system's generation costs under a nodal market compared to those in a zonal market.

Sub-question 1. How can the European power system be modeled to best reproduce its behaviour when functioning under different power market designs in combination with high and low renewable scenarios?

Firstly, and referring to the main research question, the objective of power systems is to supply the required demand with the available energy resources in the market at minimum cost. For this, TSOs use unit commitment models and constrained economic dispatch models to obtain a generating schedule that involves minimum total generation costs for the system and that is technically feasible with the physical network. Accordingly, the chosen technique to model Europe's power system is based on the optimization of energy resources from a system's viewpoint, i.e. minimization of the system's variable generation costs.

Secondly, in the context of the Internal Energy Market for Europe that aims for a competitive and efficient power system, it was chosen to model the power system from a centralised point of view as if there was a single centralized planner managing all the generating units in Europe. In this way, it is assumed that the system's optimal solution is found.

Thirdly, a major feature of power market designs in relation to the penetration of renewable energies in the system concerns the network capacity allocation method and the mechanism used to manage congestions in the lines. While in a zonal market congestion is handled through system operators with a redispatch process during the operational hour, the nodal market implicitly takes care of congestion through the market clearing by including all the network constraints in the optimization algorithm. It is precisely this difference that is used to reproduce and model both power market designs. This method reflects the efficient use of the available transmission capacity in the nodal market and the impact of the redispatch process on the system's variable generation costs in the zonal market. Moreover, the additional features included in the optimization's problem formulation related to the HVDC transmission lines in the system give a deep insight on the complexity of the network and the system's power flow problem.

Finally, the use of markedly different renewable scenarios validated by the ENTSO-E to model the system's generation mix aids to gain a clear insight, from the technological point of view, of how the different power plant technologies and their production levels in the day-ahead market are impacted by the network's topology limitations and the power market design in question.

Sub-question 2. To what extent the difference in variable electricity generation costs between scenarios and across power market designs can be attributed to an increase usage of renewable technologies, network congestions or non-served energy costs?

The research has showed that the large-scale integration of renewable energies in the power system by 2030 would lead to a reduction of 6,3% in the considered system's total variable generation costs if the latter would operate under a Copper Plate design. A lower percentage of savings would be expected provided the completion of the mechanisms to fully integrate the day-ahead markets and the completion of the required network developments that prevents significant amounts of network congestions.

Regarding the other two power market designs, despite the large rise of renewable energy production in 2030, accounting for 44,19% and 44,13% of the total energy production in the nodal and zonal markets, respectively, the power system has also required to increase the share of gas production from 15,9% to 19,6% in the nodal market and from 15,2% to 19,7% in the zonal market with respect to the reference scenario. Additionally, the incapability of the system to meet significant amounts of energy has been reflected in the share of non-served energy costs with respect to the system's total variable generation costs, 2,95% and 3,08% shares in the nodal and zonal markets, respectively. Moreover, significant renewable curtailment values of 7,83% and 8,01% in the nodal and zonal markets, respectively, reveal the system's inefficient integration of the deployed RES capacity in the system. And last but not least, the additional redispatch costs incurred in the zonal market, a 1% share of the total variable generation costs, stress even more the degree of intra-zonal congestions needed to be fixed compared to the nodal market.

All the factors above have revealed the extent of the network's congestion that provokes a share of the demand to not be met, part of the wind and solar potential to be curtailed and consequently more expensive technology to be dispatched, thus undermining the performance of an efficient power market design. The above emphasizes the relevance of having an upgraded network, whose expansion plan should be rigorously developed at the same pace as the deployment of the projected renewable energies. In order to be successful this process needs a common approach between Member States based on information exchanges and maximum transparency as well as full commitment to the project of the IEM for Europe.

Sub-question 3. How can the difference in electricity prices within and between European countries impact the markets' participants behaviour in the power market?

For a given market design, variations of electricity prices within and between countries impact on the generators' revenues depending on whether they are located upstream or downstream of the transmission constraint. On the one hand, generators' revenues are directly proportional to the nodal prices of the nodes where they are located. On the other hand, being located upstream of the transmission constraint translates into initially having assigned a higher electricity price than that of the downstream end. In the case of the zonal market, once the congestion is fixed by the TSO, the price of the upstream node would be lowered and the price of the downstream node would be increased. Therefore, generators located downstream of the transmission constraint would see an opportunity to increase their revenues. It should be noted that the more open the market is to competition and the lower the concentration of the wholesale market is, the less opportunity there is for incumbent generators to strategically bid in the market, the "inc-dec game" (Neuhoff, et al., 2011).

The research shows that in both nodal and zonal market designs weekly average nodal prices decrease in overall in a high renewable scenario. Additionally, intra-national and cross-border network congestions can be spotted, but with the analysis performed it is difficult to conclude whether these congestions are systematically present in the network. Also, these spotted congestions seem to be slightly reduced with more renewables. This could be due to the overall larger amount of renewable generation available in every node to meet the demand in each node. Following this, a point could be reached in which, provided network capacities are adequately developed, the vast presence of renewable energies in the generation mix could push wholesale prices to such low levels that revenues of both thermal and renewable energy producers could be negatively affected.

Furthermore, the base case price analysis performed shows that indeed there are some zones in the network, and hence generators located there too, that would benefit from the implementation of a nodal market since nodal prices would be slightly higher under a nodal scheme. However, for the modeled week these price differences between market designs are reduced as more renewables are integrated. Taking into account the shortcomings of the network modeled, higher differences between nodal and zonal nodal prices could be expected.

On the other hand, the results of the sensitivity analysis reflect that the lower the price that thermal generators have to pay for CO_2 emissions, the more negative are the nodal price differences between the zonal and nodal markets, and hence the more economically beneficial would be for generators bidding in the market. This output reminds that any kind of environmental policy or subsidy can impact, to a larger extent than thought, the market outcome and therefore they should be looked at carefully before implementing them. Moreover, a 50% increase in intra-zonal network capacities in a high renewable scenario would decrease the difference in nodal prices between both markets, to significantly smaller differences that would not largely impact on producers' revenues. In contrast, a 50% decrease in intra-zonal line capacities would increase nodal price differences to values of up to 25€/MWh. These magnitudes, if prolonged in time, could start impacting market participants and define whether a zonal or nodal market would be more convenient from the producers' perspective.

The price analysis performed for a future high renewable scenario, if extended to longer time horizons and different seasons, could provide further insights and a robust analysis of future congestion patterns and a possible configuration of smaller price zones for continental Europe to operate in a similar way to how the Nordic countries currently operate.

5.2. Reflection on the modeling process and results

Following the conclusions and the answers to the research questions posed in this thesis work, a reflection is presented below on the assumptions and the modeling process, the results and the limitations of the work.

As in every model representing a real-life system, many simplifying assumptions have to be made in order to model the system under computational and time constraints. In other cases, input data assumptions are needed due to the lack of accessible real data. In this regard, day-ahead markets of three phase electric power systems are usually modeled using unit commitment and transmission constrained economic dispatch models that use a linearized mathematical formulation, the so-called DC power flow model. As explained in section 2.2, the accuracy of the DC approximation to model the AC power network lies around 5% when it is applied to high voltage grids and when outcomes are averaged over all the lines in the network. This means that error deviations are acceptable as long as conclusions are not drawn for individual lines.

In relation to the required input data, it is worth mentioning that an extensive data search was necessary to comply with data as realistic as possible and many intermediate calculations with this data were required to prepare the input parameters before running the optimization model. Data assumptions related to the network are most probably among the most determining parameters to obtain power flows that conform more closely to reality. Transmission line capacities, the number of circuits in every transmission corridor and especially the relationship between line inductive reactances, are key in determining these power flows since the Power Transfer Distribution Factors (PTDFs) used in the DC power flow approximation are based on relations between reactances. Electrical characteristics of the power grids are usually not accessible to the public, therefore a reference impedance base was estimated (Appendix D) and relations between reactances of the lines were kept by using the lengths of the transmission lines.

The optimization problem is modeled with deterministic renewable scenarios that are based on scenario data provided by the ENTSO-E. Hydro energy is, however, left out from the generation mix due to lack of data. In order to account for this, the demand parameter was adjusted in those nodes of the network where hydro resources are predominant, such as in Norway or Austria. The outputs obtained from the model should therefore be interpreted knowing that optimization of hydro resources in combination with intermittent renewable sources will play an important role important role in the replacement of expensive thermal generation thanks to their flexibility and complementary use. Moreover, renewable generation of wind and solar is assigned to every node of the network according to the forecasted wind speed and solar radiation time-series in the assumed location of that node rather than on the average of a region covered by that node. This assumption induces to errors due to regional variations of the renewable sources. In the same way, the initial plan was to model the power system for two different snapshots in a year, i.e. two weeks in different seasons, in order to account for seasonal characteristic variations in wind and solar generation profiles. However, this was not possible due to lack of time and the many difficulties encountered to correct the model's inconsistent outputs.

It is important to remind the reader that the purpose of the thesis is not to predict exact values of certain model outputs but rather the interest lies in revealing trends and mechanisms that could serve for the future European power market and its design.

All in all, it should be pointed out that the outcomes obtained from the model should be interpreted baring in mind the shortcomings of the modeled network, which despite the similarity to reality of the cross-border interconnections, transmission lines within the countries are significantly simplified and therefore constraints in these parts of the network are not realistically taken into account. It is expected that with an extended and validated network topology, the outcomes of the model regarding total variable generation costs, renewable curtailment levels, non-served energy levels and the differences between nodal prices would emphasize greater differences between the nodal and zonal markets, favouring even more the nodal market scheme as an efficient alternative market design.

5.3. Recommendations

5.3.1. Guidelines for future work

Several recommendations for future research can be drawn from the present research work. While the interaction between conventional generation and different integration levels of renewable energies has been tackled in this thesis, the combination and complementary use of hydro energy resources with intermittent and uncertain energy sources like wind and solar has not been included. Hydro resources are also expected to increase, yet in a more moderate way than pure renewable energies, and their known flexibility to stabilize variations between demand and supply could play a major role in the future power system. In the context of Europe's redesign of the power system it would be interesting to study how different the market outcomes would be, especially in terms of system generation costs and network congestions.

Another aspect that could be reviewed is the perfect competition behaviour assumed in the modeling of the system. Now, it is assumed that the generators' bids reflect their marginal costs, however, in reality there is always strategic bidding to some extent. This ultimately impacts on the optimal economic dispatch and the wholesale electricity prices. However, introducing strategic behaviour of the market agents increases the complexity of the model even more.

Regarding the model's temporal scope, it is suggested that a longer time horizon is chosen to model the power system in order to obtain more robust results and conclusions. The chosen week in July could have been an unusual one in terms of renewable generation. For example, different weeks during the year or more consecutive weeks would be equally acceptable approximations.

From the network topology point of view, an increased granularity of the network to obtain a highly-meshed network closer to the real one could bring some added value to further help differentiate between the market outcomes of a nodal market and a zonal one. It would be helpful to avoid end-nodes in the network to minimize congestions that in reality would not have been there.

Also related to the network and in a similar way as was discussed in this thesis for the high-voltage power grid, changes to how congestion is managed in the distribution system will be required. A significant share of the projected renewable sources are expected to be integrated through the medium-voltage distribution systems. This will cause bidirectional flows, which were inexistent before, and they need to be taken into account. Therefore, more interaction between the Distribution System Operators (DSO) and the market will be expected. A similar analysis to this work could be done to study the impact of high penetration of renewables in the efficient operation of distribution networks.

Given the further aim of integrating short-term markets and due to increasing amounts of renewables in the system, these must increasingly be able to provide balancing power. To date, balancing reserves have been supplied by large conventional power plants and pumped-storage facilities. Some studies have already proved that renewable energies can also provide balancing power, even reacting faster than other conventional plants. However, the current framework of balancing markets prevents renewable energies from actually offering this service. An analysis on the impact of large penetration of renewables on the design and on balancing market prices could bring some light to this issue.

5.3.2. Reflection and policy implications in the European framework

The redesign of the power market involves many concerns for market players who in some way or another may be affected if implementation steps go ahead. In this section I display several reflections on some policy implications and recommendations that should be borne in mind in parallel to the redesign process of the power market.

The redesign process of Europe's power market design attempts to achieve a single and greater competitive and efficient power system. However, while market coupling has proved to improve market outcomes, regional regulations can have a negative effect on the performance of this coupled market. The national renewable policies set could tend to fragment the common market and undermine the benefits from increased energy trade. This is because renewable support schemes are still defined on a national basis and in many cases these schemes support the development of a particular technology in locations where, if looked at it from a European point of view, they are not as efficient as they would have been if placed somewhere else in the continent. An example of this could be the deployment of large amounts of solar PV panels in Germany compared to the not as many and as effective as those in Spain. This misallocation of resources, along with the excessive investments and corresponding subsidies, could have been avoided if a European framework for renewable energies would have been in place at the same time the path for the IEM was being prepared.

Harmonizing renewable policies in all Member States and replacing feed-in tariffs on a national level for a quota system on a European level could help promote cost-effective technologies in a technology-neutral way and in efficient locations. A quota system is already set up in some Nordic countries. This support scheme is quantity-based rather than setting a fixed price for renewable producers. The renewable energy quota refers to the minimum annual share of RES that electricity suppliers, large electricity consumers or electricity retailers have to meet and the high compatibility with market competitiveness and the hints it gives to transmission planners to adjust to network development requirements makes this support scheme a good candidate to apply on a European level.

A similar issue to the above could happen in relation to securing the adequacy of national capacity and reserve mechanisms. Similarly as with national renewable targets, some Member States opt for a capacity payment policy to power plants in their territories. A capacity payment represents a fixed price that is paid to generators to reward them for the capacity they can produce to guarantee security of supply, rather than what they actually produce. With this the benefits of integrating markets in Europe are not fully exploited since larger markets increase competition within capacity markets and less of this capacity would be needed in total. Moreover, depending on the magnitude of these capacity payments, this policy could distort market outcomes significantly by impacting prices in the short-term and hence influencing power plant operations nationally and internationally. The latter can lead to a welfare redistribution effect between interconnected national markets. If a Member State implements a capacity payment to ensure its generation adequacy, it will most likely positively influence the generation adequacy of an adjacent Member State with no capacity remuneration, and ultimately, the consumers in the first one will be the ones financing the generation adequacy levels of the latter. Therefore, it is crucial that the common approach of the IEM is not jeopardized by divergent policies for security of supply. Member States should be encouraged to homogenize them by European institutions.

With regards to considering a change in the market design, welfare redistribution issues can also arise between already existing generators. This issue is particularly relevant for a market shifting to a nodal scheme, in which nodal prices can experiment more drastic changes than in a zonal market, thus shifting economic surplus between actors, both generators and consumers. As a means to mitigate these congestion costs, especially during the initial implementation phases of the new market design, financial instruments such as financial transmission rights (FTRs) could become an important mechanism to alleviate impacts on revenues and high price risks. The holder of an FTR is allowed to receive the difference between two nodes prices, both of them specified in the FTR conditions. TSOs would fund this financial instrument from the congestion revenue it receives. Nonetheless, the increased variability and uncertainty in the system due to large amounts of renewable energies also increase the uncertainty for FTR holders about the congestion patterns in the lines. Therefore, new financial instruments need to be developed to address the intermittency of renewables.

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APPENDICES

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APPENDIX A

GAMS model code

WEEKLY UNIT COMMITMENT AND TRANSMISSION CONSTRAINED ECONOMIC DISPATCH OF THERMAL AND RES UNITS (SDUC AND TCED)

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$OnText
  Ainhoa Villar, based on Germán Morales SDUC model. February 24, 2015
$OffText

$OnEmpty OnMulti OffListing
* Solve the optimization problems until optimality
option Optcr = 0.001, Reslim=12000;

* Declaration of sets and indices
SETS
  p       hourly periods
  p1(p)   first hour of the day
  sc      wind scenarios (inactive set)

  g       generation units
  g1(g)   generation unit with up time equal to 1h

  i        buses
  l        dc lines
  is(i)    buses without slack bus
  iac(i)   busses connected to at least one ac line connection
  idc(i)   dc busses
  isac(i)  busses without slack bus and connected to at least one ac line connection
  c        circuit ID
  ij(i,i,c) Buses connected by a transmission line and circuit ID c
  ijac(i,i,c) Buses connected by an ac transmission line and circuit ID c
  ij2(i,i)  pairs of buses with at least one line connection
  ig(i,g)   location of generator g in node i

   alias(p,pp)
   alias(i,j)
   alias(c,cc)
   alias(i,ii)
   alias(l,ll)
;

PARAMETERS
*Parameters related to hourly periods
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pDemand(p,i) demand for every hour p in every node i [GW]
pPMaxWindGen(i,p) stochastic wind generation for every scenario every hour & every node [GW]

pSwProb(sc) probability of scenario sc [pu]
pENScost cost of energy not served [M€ per GWh]

***Parameters related to generator units**
pMaxProd(g) Maximum output of generator g [GW]
pMinProd(g) Minimum output of generator g [GW]
pIniProd(g) Initial output of unit g [GW]
pIniProd1(g) Initial output of unit g above minimum output [GW]
pIniState(g) Initial state of unit g [h]
pIniUC(g) Initial commitment of unit g [0-1]
pIniUp(g)
pIniDw(g)
pRampUp(g) Ramp up of unit g [GW per h]
pRampDw(g) Ramp down of unit g [GW per h]
pMinUpT(g) Minimum upward time of unit g [h]
pMinDwT(g) Minimum downward time of unit g [h]

pFuelCost(g) Cost of fuel used by generator g [M€ per GWh]
pOMCost(g) Variable operation cost & maintenaince cost for generator g [M€ per GWh]
pMargCost(g) Marginal cost for generator g [M€ per GWh]
pFixedFuelCost(g) Fixed fuel consumption of generator g [M€ per h]
pStartUpCost(g) startup cost [M€ per GW]
pShutDownCost(g) shutdown cost [M€ per GW]
pEmissionRate(g) emission rate of generator g [tCO2 per GWh]
pCO2Cost CO2 emission cost rate [M€ per tCO2]
pFuelType(g) Fuel type identification

***Parameters related to the network**
pPTDF(i,j,c,i) Power Transfer Distribution Factors Matrix for line ij circuit ID c and node i
Adc(l,i) Incidence matrix of HVDC lines
pBranchMaxPower(i,j,c) Maximum power flow for line ij
pDCMax(l) Maximum power output of HVDC line l

***Parameters for post-calculations**
pExpnr Experiment number

*pLMPac(p,i,sc) locational marginal price in node i for hour p and scenario sc [M€ per GWh]
*pLMPdc(p,i,sc) locational marginal price in node i for hour p and scenario sc [M€ per GWh]

pPnet(i,p,sc) Net production (Production-Demand+ENS) of evey node i in every hour p [GW]
pPnet2(i,p,sc)
pNetInflowDC(i,p,sc) Net inflow due to DC lines in every node i for every hour p [GW]
pNetInflowDC2(i,p,sc)
pNetInflowAC(i,p,sc) Net inflow due to AC lines in every node i for every hour p [GW]
pNetInflowAC2(i,p,sc)
pNetInflow(i,p,sc) Total net inflow due to all lines (DC and AC) in every node i in every hour p [GW]

```
  pSummary(*)
  pTotal(g,p,sc)
;

* Declaration of free variables
VARIABLES
   vTotalVCost          total system variable cost [M€]
   vPBranch(i,j,c,p,sc) power flow through branch i -> j and circuit c for every hour p & scenario sc [GW]
   vPDCline(l,p,sc)     power flow through dc line l for every hour p and scenario sc [GW]
;

POSITIVE VARIABLES
  vProduct  (g,p,sc) output of the unit g for hour p and scenario sc [GW]
  vProduct1 (g,p,sc) output of the unit g > min load for hour p and scenario sc [GW]
  vUpReserve(p,g,sc) operating reserve up of unit g for hour p and scenario sc [GW]
  vDwReserve(p,g,sc) operating reserve down of unit g for hour p and scenario sc [GW]
  vENS      (p,i,sc) energy not served in node i for every hour p and every scenario sc [GW]
  vIG       (i,p,sc) intermittent generation in node i for every hour p and every scenario sc [GW]

BINARY VARIABLES
  vCommitt  (g,p) commitment of the unit g in hour p [0-1]
  vStartup  (g,p) startup of the unit g in hour p [0-1]
  vShutdown (g,p) shutdown of the unit g in hour p [0-1]

* Declaration of Equations
EQUATIONS
  eTotalVCost      total system variable cost     [M€]
  eBalance  (p,sc) load generation balance in hour p for scenario sc [GW]

 eThrmMax (g,p,sc) max output of the committed unit g (with uptime and downtime greater than 1h) in
hour p and scenario sc [GW]
  eThrmMax2 (g,p,sc) max output of the committed unit g (with uptime lower than 2h) in hour p and
scenario sc [GW]
  eThrmMax3 (g,p,sc) max output of the committed unit g (with downtime lower than 2h) in hour p and
scenario sc [GW]
  eThrmMin  (g,p,sc) min output of the committed unit g in hour p and scenario sc [GW]
  eTotOutput(g,p,sc) total output of committed unit g in hour p [GW]

  eRampUp   (g,p,sc) bound on ramp up of unit g in hour p [GW]
  eRampDw   (g,p,sc) bound on ramp down of unit g in hour p [GW]

  eMinTUp   (g,p) minimum up   time (committed)
  eMinTDown (g,p) minimum down time (not committed)

  eUCStrShut(g,p) relation between commitment startup and shutdown decision

  ePBranch(p,i,j,c,sc)     Network constraints of line ij circuit c for hour p and scenario sc
  ePDCnodes(p,i,sc)        Balance equation for DC nodes
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* Formulation of equations:
eTotalVCost     .. vTotalVCost =e= sum[(p,i,sc), pENSCost*vENS(p,i,sc)                   ] +
                   sum[(p,g,sc), pEmissionRate(g)*pCO2Cost*vProduct(g,p,sc)           ] +
                   sum[(p,g,sc), pMargCost(g)*vProduct(g,p,sc)                        ] +
                   sum[(p,g), pFixedFuelCost(g)*vCommitt(g,p)                         ] +
                   sum[(p,g), pStartupCost(g)*vStartup(g,p)*pMaxProd(g)               ] +
                   sum[(p,g), pShutDownCost(g)*vShutdown(g,p)                         ];

*Balance Demand with Production of thermal generation and IG & ENS in the system every hour p
eBalance  (p,sc)     .. sum[g, vProduct(g,p,sc)] + sum[i,vIG(i,p,sc)+vENS(p,i,sc)] =e=sum[i,
pDemand(p,i)];

*Capacity Limits
eThrmMax  (g,p,sc) $[not(g1(g))] ..  vProduct1(g,p,sc) +vUpReserve(p,g,sc)=l= (pMaxProd(g)-
pMinProd(g))*(vCommitt(g,p) - vStartup(g,p) - vShutdown(g,p+1));

eThrmMax2 (g1(g),p,sc)          ..  vProduct1(g,p,sc) +vUpReserve(p,g,sc)=l= (pMaxProd(g)-
pMinProd(g))*(vCommitt(g,p) - vStartup(g,p));

eThrmMax3 (g1(g),p,sc)          ..  vProduct1(g,p,sc) +vUpReserve(p,g,sc)=l= (pMaxprod(g)-
pMinProd(g))*(vCommitt(g,p) - vShutdown(g,p+1));

eThrmMin  (g,p,sc)            ..  vProduct1(g,p,sc)-vDwReserve(p,g,sc) =g= 0;

*Power Output of unit g always above technical minimum
eTotOutput(g,p,sc)              .. vProduct(g,p,sc) =e= pMinProd(g)*vCommitt(g,p) + vProduct1(g,p,sc) ;

*Ramping constraints
eRampUp(g,p,sc)               .. vProduct1(g,p,sc)-vProduct1(g,p-1,sc)-pIniProd1(g) $p1(p) =l=
pRampUp(g) ;

eRampDw(g,p,sc)               ..-vProduct1(g,p,sc)+vProduct1(g,p-1,sc)+pIniProd1(g) $p1(p) =l=
pRampDw(g) - (pRampDw(g)-(pMinProd(g)-pMinProd(g)))*vShutDown(g,p)$p1(p);

*Relation between commitment startup and shutdown decision
eUCStrShut(g,p)              .. vCommitt(g,p) - vCommitt(g,p-1) - pIniUC(g) $p1(p) =e= vStartup(g,p) -
vShutdown(g,p) ;

*Minimum Time Up and Minimum Time Down
eMinTUp(g,p) $[ord(p)>=pMinUpT(g)]   .. sum[pp$(ord(pp)>=(ord(p)-pMinUpT(g)+1) and
ord(pp)<=ord(p)),vStartup (g,pp)] =l=     vCommitt(g,p);

eMinTDown(g,p) $[ord(p)>=pMinDwT(g)] .. sum[pp$(ord(pp)>=(ord(p)-pMinDwT(g)+1) and
ord(pp)<=ord(p)),vShutdown(g,pp)] =l= 1 - vCommitt(g,p);

*Network constraint 1
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ePBranch(p,i,j,c,sc) $[ijac(i,j,c)]    ..vPBranch(i,j,c,p,sc)  =E= SUM[isac, pPTDF(i,j,c,isac)*(SUM [g $
ig(isac,g),vCommitt(g,p)*pMinProd(g)+ vProduct1(g,p,sc)] - pDemand(p,isac) +vENS(p,isac,sc) +
vIG(isac,p,sc) + SUM[l , Adc(l,isac) * vPDCline(l,p,sc) ] ) ] ;

*Network constraint 2
ePDCnodes(p,i,sc)    $[idc(i)]        ..SUM [g $ ig(i,g),vCommitt(g,p)*pMinProd(g)+ vProduct1(g,p,sc)] -
pDemand(p,i) +vENS(p,i,sc) + vIG(i,p,sc) =E= -SUM[l , Adc(l,i) * vPDCline(l,p,sc) ]  ;


********************************************************************************************
*********************OBTAINING PARAMETERS**************************************

sets
$include  indicesV1
;
$include paramV1
;
table     pDemand2(p,i) thermal generation parameters
$include  demandV1
;
table     pPMaxWindEnergy(p,i) thermal generation parameters
$include  RESproductionV1
;
table     pThermalGen(g,*) thermal generation parameters
$include  thermalgenV1
;
table     pNetwork(i,j,c,*) network parameters
$include  ACnetworkV1
;
table     pDClines(l,*) dummy generators parameters
$include  DClinesV1
;

********************************************************************************************
********************SCALING PARAMETERS****************************************

* Scaling of parameters from MW and € to GW and M€ from €/MWh  to M€/GWh
pDemand(p,i) = pDemand2(p,i) * 1e-3 ;
pPMaxWindGen(i,p)= pPMaxWindEnergy(p,i) * 1e-3;

pMaxProd       (g)    = pThermalGen(g,'MaxProd') * 1e-3 ;
pMinProd       (g)    = pThermalGen(g,'MinProd') * 1e-3 ;
pIniProd       (g)    = pThermalGen(g,'IniProd') * 1e-3 ;
pIniState      (g)    = pThermalGen(g,'IniState')          ;
pRampUp        (g)    = pThermalGen(g,'RampUp') * 1e-3 * 100  ;
pRampDw        (g)    = pThermalGen(g,'RampDw') * 1e-3 * 100;
pMinUpT        (g)    = pThermalGen(g,'MinUpTime'   )        ;
pMinDwT        (g)    = pThermalGen(g,'MinDwTime'   )        ;
pFixedFuelCost  (g)    = pThermalGen(g,'FixedFuelCost') * 1e-6 ;
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pMargCost      (g)    = pThermalGen(g,'MarginalCost') * 1e-3 ;
pShutDownCost  (g)      = pThermalGen(g,'ShutDownCost'   )*1e-3    ;
pStartUpCost   (g)      = pThermalGen(g,'StartUpCost'    ) * 1e-3 ;
pEmissionRate(g)        = pThermalGen(g,'EmissionRate'   ) * 1e3 ;
pFuelType(g)            = pThermalgen(g,'FuelType');
pBranchMaxPower(i,j,c)  = pNetwork(i,j,c,'Pmax') * 1e-3;
pDCmax(l)              =pDClines(l,'Pmax') * 1e-3;

 *********************************************************************************
***************LOADING NETWORK INFO, ASSIGNMENT OF SETS***********************
g1(g) $[pMinUpT(g)=1] = yes;

execute_load 'PTDF.gdx' isac,is,pPTDF,ijac, Adc, iac, idc;
display pPTDF ;
*Assignment of thermal generators g to their corresponding buses i
ig(i,g) $[ord(i) = pThermalGen(g,'Bus')] = YES;
display ig ;

is(i) = is(i)*(SUM[g,ig(i,g)]);
display is ;
ij(i,j,c) $ pNetwork(i,j,c,'Pmax') = YES;
display ij ;

 *********************************************************************************
***********BOUNDS ON VARIABLES, OTHER DATA & INITIAL CONDITIONS**************

*Allowing curtailment of Wind and Solar
vIG.up(i,p,sc)= pPMaxWindGen(i,p) ;

* Bounds on variables
vStartup.up(g,p)       = 1 ;
vShutdown.up(g,p)  = 1 ;
vStartup.lo(g,p)       = 0 ;
vShutdown.lo(g,p)   = 0 ;

vProduct1.up    (g,p,sc)    = pMaxProd(g)-pMinProd(g);
vUpReserve.up   (p,g,sc)  = pMaxProd(g)-pMinProd(g);
vDwReserve.up  (p,g,sc) = pMaxProd(g)-pMinProd(g);

vPBranch.up(i,j,c,p,sc)    =  pBranchMaxPower(i,j,c);
vPBranch.lo(i,j,c,p,sc)     = -pBranchMaxPower(i,j,c);

vPDCline.up(l,p,sc)         =  pDCmax(l);
vPDCline.lo(l,p,sc)          = -pDCmax(l);

*Other entry data
* Determine the first hour of the day
p1(p) $[ord(p) = 1] = yes ;
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* Definition of the cost of non-served energy M€/GWh
pENScost=0.2;

*Definition of the cost of CO2 emission cost rate M€/tonnes of CO2
pCO2Cost=0.0001;

* If the initial output of the unit is above its minimum load then the unit is committed, otherwise it is not committed
pIniUC(g)= 1 $[pIniProd(g) >= pMinProd(g)] ;
pIniProd1(g)=(pIniProd(g)-pMinProd(g))*pIniUC(g);
display pIniProd1, pIniUC ;

* If the minimum up or down times are 0, they are changed to 1h
pMinUpT(g) $[pMinUpT(g) = 0] =   1 ;
pMinDwT(g) $[pMinDwT(g) = 0] =   1 ;

*Initial up/dw/Start-Up conditions
pIniUp(g) $[pIniState(g)>=0] =     pIniState(g) ;
pIniDw(g) $[pIniState(g)< 0] = abs(pIniState(g));

* SOLVER OPTIONS
* Selection of the solver for linear programming problems
OPTION LP = Cplex;

* Maximum number of iterations that are allowed
*OPTION ITERLIM = 100000;

file COPT      / cplex.opt                        /
put  COPT putclose 'rinsheur 200' /;

model UCandTCED / all/ ;
UCandTCED.solprint = 0 ;
UCandTCED.holdfixed = 1 ;
UCandTCED.optfile = 1;
*model UCandTCED / eTotalVCost, eBalance, eOpReserve, eReserveUp, eReserveDw,
*           eMaxOutput, eMinOutput, eTotOutput, eRampUp, eRampDw,
*           eUCStrShut, eMinTUp, eMinTDown, ePBranch
*          /;

* Solve the stochastic daily unit commitment & transmission constrained economic dispatch model
solve UCandTCED using MIP minimizing vTotalVCost;

pSummary('NumEqs')     = UCandTCED.Numequ;
pSummary('NumRealVar') = UCandTCED.Numvar - UCandTCED.Numdvar - 1;
pSummary('NumBinVar')  = UCandTCED.Numdvar;
pSummary('OptMILP')    = UCandTCED.Objval;
pSummary('CPUTime')    = UCandTCED.Resusd;
pSummary('NonZeros')   = UCandTCED.Numnz;
pSummary('OptRMIP')    = UCandTCED.Objval+eps;
```

pSummary('RGap') = (UCandTCED.Objest-UCandTCED.Objval)/UCandTCED.Objval + eps;
pSummary('Iters') = UCandTCED.Iterusd+eps;
pSummary('Nodes') = UCandTCED.Nodusd+eps;
pSummary('SolStat') = UCandTCED.solvestat;
pSummary('LBound') = UCandTCED.Objest+eps;

****
********************CALCULATION OF OUTPUT VARIABLES*************************

***Calculation of LMPs, nodal prices finally done in MATLAB**
***For nodes that are connected to both AC and HVDC lines:**
*pLMPac(p,iac,sc) = eBalance.m(p,sc) + sum[(j,c), pPTDF(iac,j,c,iac)*ePBranch.m(p,iac,j,c,sc)];

***For nodes that are connected only to HVDC lines:**
*pLMPdc(p,idc,sc) = eBalance.m(p,sc) + ePDCnodes.m(p,idc,sc);

display eBalance.m, ePBranch.m, ePDCnodes.m;

***Calculation of Commitment Planning Costs, Operation and Non-served energy Costs:**
parameter pPlanningCost, pOperationCost, ensCost;

pPlanningCost = sum[(p,g), pFixedFuelCost(g)*vCommitt.l(g,p)] +
sum[(p,g), pStartupCost(g)*vStartup.l(g,p)*pMaxProd(g)] +
sum[(p,g), pShutDownCost(g)*vShutdown.l(g,p)];

ensCost = sum[(p,i,sc), pENSCost*vENS.l(p,i,sc)];

pOperationCost = vTotalVCost.l - pPlanningCost - ensCost;

***Calculation of aggregated production in every node i of generators located in that node**
parameter pAggrProd(i,p,sc);
pAggrProd(i,p,sc) = sum[g $ig(i,g), vProduct.l(g,p,sc)] ;

***Calculation of Net inflow (Inflow-Outflow) in every node i for every hour p due to HVDC lines**
pNetInflowDC(i,p,sc) = SUM[l , Adc(l,i) * vPDCline.l(l,p,sc)] ;
pNetInflowDC2(i,p,sc) = pNetInflowDC(i,p,sc) + EPS;

***Calculation of Net inflow (Inflow-Outflow) in every node i for every hour p due to AC lines**
pNetInflowAC(i,p,sc) = sum[(j,c) $ij(j,i,c), vPBranch.l(j,i,c,p,sc)] - sum[(j,c) $ij(i,j,c), vPBranch.l(i,j,c,p,sc)];
pNetInflowAC2(i,p,sc) = pNetInflowAC(i,p,sc) + EPS;

***Calculation of Net inflow in every node i for every hour p due to AC and HVDC lines**
pNetInflow(i,p,sc) = pNetInflowDC2(i,p,sc) + pNetInflowAC2(i,p,sc);

***Renaming pDemand to reposition indexes**
parameter pDemand3(i,p);
pDemand3(i,p)= pDemand(p,i);
***Renaming pENS to reposition indexes**

```
parameter pENS(i,p,sc);
pENS(i,p,sc)=vENS.l(p,i,sc);

*Calculation of hourly curtailment and % of hourly RES Curtailment in the whole system
parameter pTotalCurtailment(p,sc), pCurtailment(p,sc), pPMaxWindGen2(i,p);
pPMaxWindGen2(i,p)=pPMaxWindGen(i,p) + EPS;

pTotalCurtailment(p,sc)=sum[i, (pPMaxWindGen2(i,p) - vIG.l(i,p,sc)) ];
pCurtailment(p,sc)= pTotalCurtailment(p,sc) / [sum[i, pPMaxWindGen2(i,p)]] * 100;

 ***********************************************************************************
******************WRITE OUTPUT VARIABLES IN TEXT FILE*************************

file summaryout /"Summary.txt"/ ; summaryout.pc=6;
put summaryout ;
put "----------------" /
put "General information" /
put "----------------" /
put 'Expnr     ' ,      pExpnr:<3:0 /
put "program execution date ",  system.date  /
put "program execution time",   system.time /
put "title of the model",       system.title/
put "input file name",          system.ifile /
put "output file name",         system.ofile /
*put "current file page",       system.page  /
*put "restart file date",       system.rdate /
*put "restart file name",       system.rfile /
*put "restart file time",       system.rtime /
*put "save file name",          system.sfile /
put "----------------" /
put "Solution Summary" /
put "----------------" /
put "NumEqs    " ,      pSummary('NumEqs'):<8:0 /
put "NumRealVar" ,      pSummary('NumRealVar'):<8.0 /
put "NumBinVar " ,      pSummary('NumBinVar'):<8.0 /
put "OptMILP   " ,      pSummary('OptMILP'):<8.6 /
put "CPUTime   " ,      pSummary('CPUTime'):<8.6 /
put "NonZeros  " ,      pSummary('NonZeros'):<8.0 /
put "OptRMIP   " ,      pSummary('OptRMIP'):<8.6 /
*put "IntGap   " ,      pSummary('IntGap'):<8.0 /
*put "OptRMIP  " ,      pSummary('OptRMIP'):<8.0 /
put "RGap      " ,      pSummary('RGap'):<8.6 /
put "Iters     " ,      pSummary('Iters'):<8.0 /
put "Nodes     " ,      pSummary('Nodes'):<8.0 /
put "SolStat   " ,      pSummary('SolStat'):<8.0 /
put "LBound    " ,      pSummary('LBound'):<8.6 /
put "----------------" / ;

*Power flows through AC and HVDC lines
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```
file actxtout /"AClineFlows.txt"/ ; actxtout.pc=5;
  put actxtout ;
  put '# Exprnr' pExpnr:<3:0 /
  loop((i,j,c,p,sc), put$(ijac(i,j,c)), i.tl, j.tl, c.tl, p.tl, vPBranch.l(i,j,c,p,sc):<15:8 /);

file dctxtout /"DClineFlows.txt"/ ; dctxtout.pc=5;
  put dctxtout ;
  put '# Exprnr' pExpnr:<3:0 /
  loop((l,p,sc), put, l.tl, p.tl, vPDCline.l(l,p,sc):<15:8 /);

*Production of generators
file prodtxtout /"Production.txt"/ ; prodtxtout.pc=5;
  put prodtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((g,p,sc), put, g.tl, p.tl, vProduct.l(g,p,sc):<20:10 /);

*Generator Type
file gentypetxtout /"GeneratorType.txt"/ ; gentypetxtout.pc=5;
  put gentypetxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((g), put, g.tl, pThermalgen(g,'FuelType'):<1:0 /);

*RES production
file restxtout /"RESproduction.txt"/ ; restxtout.pc=5;
  put restxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p,sc), put, i.tl, p.tl, vIG.l(i,p,sc):<20:10 /);

file maxrestxtout /"MaximumRES.txt"/ ; maxrestxtout.pc=5;
  put maxrestxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p), put, i.tl, p.tl, pPMaxWindGen2(i,p):<10:8 /);

*Aggregated production in every node of the generators located in that node
file aggrprodtxtout /"AggregatedProduction.txt"/ ; aggrprodtxtout.pc=5;
  put aggrprodtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p,sc), put, i.tl, p.tl, pAggrProd(i,p,sc):<10:8 /);

*Demand
file demtxtout /"Demand.txt"/ ; demtxtout.pc=5;
  put demtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p), put, i.tl, p.tl, pDemand3(i,p):<20:10 /);

*Total curtailment and % curtailment
file totalcurttxtout /"TotalCurtailment.txt"/ ; totalcurttxtout.pc=5;
  put totalcurttxtout ;
  put '# Exprnr' pExpnr:<3:0 /
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```
   loop((p,sc), put, p.tl, pTotalCurtailment(p,sc):<10:8 /);

file curttxtout /"Curtailment.txt"/ ; curttxtout.pc=5;
  put curttxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((p,sc), put, p.tl, pCurtailment(p,sc):<6:3 /);

file netintxtout /"NetInflow.txt"/ ; netintxtout.pc=5;
  put netintxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p,sc), put, i.tl, p.tl, pNetInflow(i,p,sc):<15:8 /);
```

***Non-served energy**

```
file enstxtout /"ENS.txt"/ ; enstxtout.pc=5;
  put enstxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,p,sc), put, i.tl, p.tl, pENS(i,p,sc):<20:10 /);
```

***Costs**

```
file coststxtout /"Costs.txt"/ ; coststxtout.pc=5;
  put coststxtout ;
  put '# Exprnr',pExpnr:<3:0 /
  put 'Generation Costs',vTotalVcost.l:<20:3 /
  put 'Planning Costs',pPlanningCost:<20:3 /
  put 'Operation Costs',pOperationCost:<20:3 /;
```

***Commitment, Startup and Shutdown**

```
file commtxtout /"Commitment.txt"/ ; commtxtout.pc=5;
  put commtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((g,p), put, g.tl, p.tl, vCommitt.l(g,p):<1:0 /);

file startxtout /"Startup.txt"/ ; startxtout.pc=5;
  put startxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((g,p), put, g.tl, p.tl, vStartup.l(g,p):<1:0 /);

file shuttxtout /"Shutdown.txt"/ ; shuttxtout.pc=5;
  put shuttxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((g,p), put, g.tl, p.tl, vShutdown.l(g,p):<1:0 /);
```

***Network Information**

```
file acnetwtxtout /"ACNetwork.txt"/ ; acnetwtxtout.pc=5;
  put acnetwtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((i,j,c), put$(ijac(i,j,c)), i.tl, j.tl, c.tl, pNetwork(i,j,c,'Pmax'):<15:8  /);

file dcnetwtxtout /"DCNetwork.txt"/ ; dcnetwtxtout.pc=5;
```

```
  put dcnetwtxtout ;
  put '# Exprnr' pExpnr:<3:0 /
   loop((l), put, l.tl, pDClines(l,'Pmax'):<15:8 /);

file ptdfout /"PTDF.txt"/ ; ptdfout.pc=5;
   put ptdfout ;
   put "Expnr" ,      pExpnr:<3:0 /
   put "fromN", "toN", "c", loop(i, put$(isac(i)), i.tl) put / ;
   loop((i,j,c), put$(ijac(i,j,c)), i.tl, j.tl, c.tl, loop(ii, put$(pPTDF(i,j,c,ii)), pPTDF(i,j,c,ii):<10:8 )
put$(ijac(i,j,c)) / );
```

***Dual Variables**

```
file lambdaout /"Lambda.txt"/ ; lambdaout.pc=5;
   put lambdaout ;
   put "Expnr" ,      pExpnr:<3:0 /
   loop((p,sc), put,  p.tl, eBalance.m(p,sc):<20:10 /);

file muout /"Mu.txt"/ ; muout.pc=5;
   put muout ;
   put "Expnr" ,      pExpnr:<3:0 /
   loop((i,j,c,p,sc), put$(ijac(i,j,c)), i.tl, j.tl, c.tl, p.tl, vPBranch.m(i,j,c,p,sc):<20:10 /);

$ontext
file mudcout /"MuDC.txt"/ ; mudcout.pc=5;
  put mudcout ;
  put '# Exprnr' pExpnr:<3:0 /
  loop((l,p,sc), put, l.tl, p.tl, vPDCline.m(l,p,sc):<20:10 /);
$offtext

file lambdadcout /"LambdaDC.txt"/ ; lambdadcout.pc=5;
  put lambdadcout ;
  put '# Exprnr' pExpnr:<3:0 /
  loop((i,p,sc), put$(idc(i)), i.tl, p.tl, ePDCnodes.m(p,i,sc):<20:10 /);

 *********************************************************************************
```

APPENDIX B

Generation mix of the system, per country and per scenario

Table B.1. Generation mix of the system. Total capacity installed (GW) in every scenario.

	Wind	Solar	RES	Nuclear	Lignite	Hard Coal (Anthracite + Coal)	Gas (Natural Gas + Gas)	Fuel Oil (Light + Heavy)	Total
Scenario B 2014	76,5	59,0	135,5	104,2	37,5	88,6	130,4	34,1	530,2
Scenario EU 2020	157,2	94,6	251,8	99,5	34,3	76,2	135,4	25,0	622,1
Vision 1 2030	157,0	96,2	253,2	87,1	27,6	61,2	147,4	5,9	582,4
Vision 2 2030	157,0	96,2	253,2	85,3	27,6	61,2	136,8	5,9	570,0
Vision 3 2030	256,5	158,6	415,1	77,5	30,8	51,7	172,0	9,6	756,6
Vision 4 2030	325,5	189,1	514,6	77,9	26,4	45,6	167,8	9,6	841,9

Table B.2. Generation mix of the system. Increased installed capacity (%) in every scenario.

	Wind	Solar	RES	Nuclear	Lignite	Hard Coal (Anthracite + Coal)	Gas (Natural Gas + Gas)	Fuel Oil (Light + Heavy)	Total
Scenario B 2014									
Scenario EU 2020 (1)	105,56	60,25	85,83	-4,55	-8,30	-14,00	3,81	-26,76	17,33
Vision 1 2030 (2)	-0,13	1,74	0,57	-12,46	-19,55	-19,63	8,85	-76,46	-6,39
Vision 2 2030 (3)	-0,13	1,74	0,57	-14,26	-19,55	-19,63	1,04	-76,47	-8,37
Vision 3 2030 (4)	63,16	67,73	64,88	-22,11	-10,36	-32,09	27,03	-61,66	21,63
Vision 4 2030 (5)	107,08	99,99	104,42	-21,62	-23,19	-40,15	23,91	-61,66	35,33

(1): with respect to B 2014
(2): with respect to EU 2020
(3): with respect to EU 2020
(4): with respect to EU 2020
(5): with respect to EU 2020

Thermal, Wind & Solar capacity installed (%) associated to the national yearly targets for RES shares in electricity in 2014-2030.

Source: ENTSO-E (Scenario B for 2014, Scenario EU for 2020 and the Visions for 2030).

Table B.3. Generation mix per country. Capacity installed (%) in scenario B 2014.

Country	Wind %	Solar %	Nuclear %	Lignite %	Hard Coal %	Gas %	Fuel Oil %
Netherlands	9	2	2	0	19	65	3
Germany	21	22	7	13	18	17	2
Austria	19	4	0	0	0	77	0
Belgium	10	15	33	0	2	39	1
France	9	5	63	0	5	6	12
Norway	41	0	0	0	0	59	0
Denmark	48	6	0	0	24	22	0
Sweden	20	0	50	0	1	5	24
UK	12	0	13	0	28	44	3
Poland	11	0	0	26	60	3	0
Czech Republic	2	13	23	46	8	8	0
Italy	9	19	0	0	9	44	18
Total (%)	14	11	20	7	17	25	6

Table B.4. Generation mix per country. Capacity installed (%) in scenario EU 2020.

Country	Wind %	Solar %	Nuclear %	Lignite %	Hard Coal %	Gas %	Fuel Oil %
Netherlands	21	9	1	0	12	54	3
Germany	33	25	4	9	13	14	1
Austria	24	3	0	0	0	73	0
Belgium	22	18	23	0	0	36	0
France	21	12	52	0	2	6	7
Norway	68	0	0	0	0	32	0
Denmark	56	10	0	0	10	17	6
Sweden	33	0	52	0	1	4	12
UK	27	0	12	0	20	40	1
Poland	16	1	0	22	55	6	0
Czech Republic	3	14	21	45	6	10	0
Italy	12	27	0	0	8	38	14
Total (%)	25	15	16	6	12	22	4

Table B.5. Generation mix per country. Capacity installed (%) in Vision 1, 2030.

Country	Wind	Solar	Nuclear	Lignite	Hard Coal	Gas	Fuel Oil
	%	%	%	%	%	%	%
Netherlands	21	14	2	0	18	45	0
Germany	33	31	0	8	16	10	1
Austria	20	5	0	0	7	65	2
Belgium	23	19	0	0	0	58	0
France	20	12	57	0	2	8	2
Norway	76	0	0	0	0	24	0
Denmark	48	8	0	0	20	24	0
Sweden	37	0	59	0	0	0	4
UK	32	2	11	0	4	50	1
Poland	27	2	14	22	29	6	0
Czech Republic	4	10	26	29	8	23	0
Italy	14	25	0	0	12	47	2
Total (%)	27	17	15	5	11	25	1

Table B.6. Generation mix per country. Capacity installed (%) in Vision 2, 2030.

Country	Wind	Solar	Nuclear	Lignite	Hard Coal	Gas	Fuel Oil
	%	%	%	%	%	%	%
Netherlands	21	14	2	0	18	45	0
Germany	34	31	0	8	16	9	1
Austria	21	5	0	0	8	64	2
Belgium	23	19	0	0	0	58	0
France	20	12	57	0	2	7	2
Norway	76	0	0	0	0	24	0
Denmark	49	8	0	0	21	23	0
Sweden	41	0	54	0	0	0	4
UK	34	2	12	0	4	47	1
Poland	27	2	14	22	29	6	0
Czech Republic	4	11	27	31	8	20	0
Italy	14	26	0	0	12	46	3
Total (%)	28	17	15	5	11	24	1

Table B.7. Generation mix per country. Capacity installed (%) in Vision 3, 2030.

Country	Wind	Solar	Nuclear	Lignite	Hard Coal	Gas	Fuel Oil
	%	%	%	%	%	%	%
Netherlands	29	19	0	0	13	39	0
Germany	37	30	0	6	10	18	1
Austria	30	19	0	0	7	43	2
Belgium	32	22	0	0	0	46	0
France	31	23	31	0	1	10	3
Norway	85	0	0	0	0	15	0
Denmark	53	17	0	0	14	16	0
Sweden	49	4	44	0	0	0	3
UK	46	5	12	0	5	32	1
Poland	25	2	15	29	10	18	0
Czech Republic	3	9	34	26	7	21	0
Italy	16	36	0	0	8	35	4
Total (%)	34	21	10	4	7	23	1

Table B.8. Generation mix per country. Capacity installed (%) in Vision 4, 2030.

Country	Wind	Solar	Nuclear	Lignite	Hard Coal	Gas	Fuel Oil
	%	%	%	%	%	%	%
Netherlands	30	22	1	0	11	36	0
Germany	45	27	0	5	7	15	0
Austria	26	31	0	0	5	36	2
Belgium	33	24	0	0	0	42	0
France	33	31	25	0	1	8	2
Norway	93	0	0	0	0	7	0
Denmark	55	16	0	0	13	16	0
Sweden	62	3	33	0	0	0	2
UK	48	5	11	0	5	31	0
Poland	34	12	13	16	9	16	0
Czech Republic	5	15	32	24	5	19	0
Italy	17	37	0	0	7	35	4
Total (%)	38,66	22,46	9	3	5	20	1

Wind & Solar capacities installed (MW) associated to each country's yearly targets for RES shares in electricity in 2014-2030.
Source: ENTSO-E (Scenario B for 2014, Scenario EU for 2020 and the Visions for 2030)

Table B.9. Installed capacities for wind and solar technologies in every country and in every scenario (MW).

Country	Scenario B 2014		EU 2020		Vision 1 2030	
	Wind	Solar	Wind	Solar	Wind	Solar
Netherlands	2710	760	7780	3500	6000	4000
Germany	34720	36330	65790	49670	59300	55100
Austria	1900	400	2600	320	3290	820
Belgium	1720	2680	4900	4050	4790	4050
France	9000	5100	25000	15000	20000	12000
Norway	800	0	2800	0	2750	0
Denmark	4800	560	6850	1250	6850	1110
Sweden	3980	0	6400	0	6250	0
UK	7790	0	20310	0	30570	1870
Poland	3440	0	5850	270	8400	500
Czech Republic	310	2150	570	2500	740	2000
Italy North (60% of installed capacity in whole country)	5298	11028	8340	18000	8046	14760
Total (GW)	76,468	59,008	157,19	94,56	156,986	96,21

Table B.10. Installed capacities for wind and solar technologies in every country and in every scenario (MW) (continuation).

Country	Vision 2 2030		Vision 3 2030		Vision 4 2030	
	Wind	Solar	Wind	Solar	Wind	Solar
Netherlands	6000	4000	12000	8000	12800	9100
Germany	59300	55100	85000	68800	113100	68800
Austria	3290	820	5500	3500	5500	6500
Belgium	4790	4050	8540	5740	9370	6740
France	20000	12000	40000	30000	52400	49600
Norway	2750	0	5000	0	11400	0
Denmark	6850	1110	10460	3430	11460	3430
Sweden	6250	0	11100	1000	19000	1000
UK	30570	1870	54870	5800	60370	5800
Poland	8400	500	10000	1000	15600	5300
Czech Republic	740	2000	740	2000	1250	3500

Italy North (60% of installed capacity in whole country)	8046	14760	13260	29340	13260	29340
Total (GW)	156,986	96,21	256,47	158,61	325,51	189,11

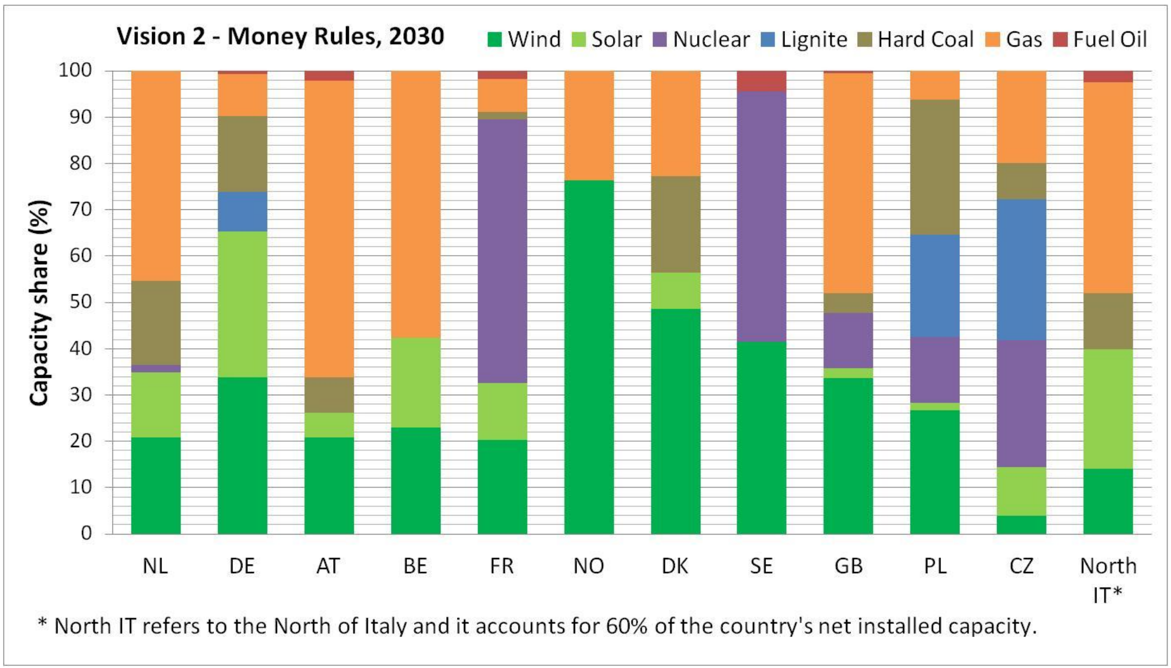

Figure B.1 . Breakdown of generation mix per country in Vision 2 year 2030

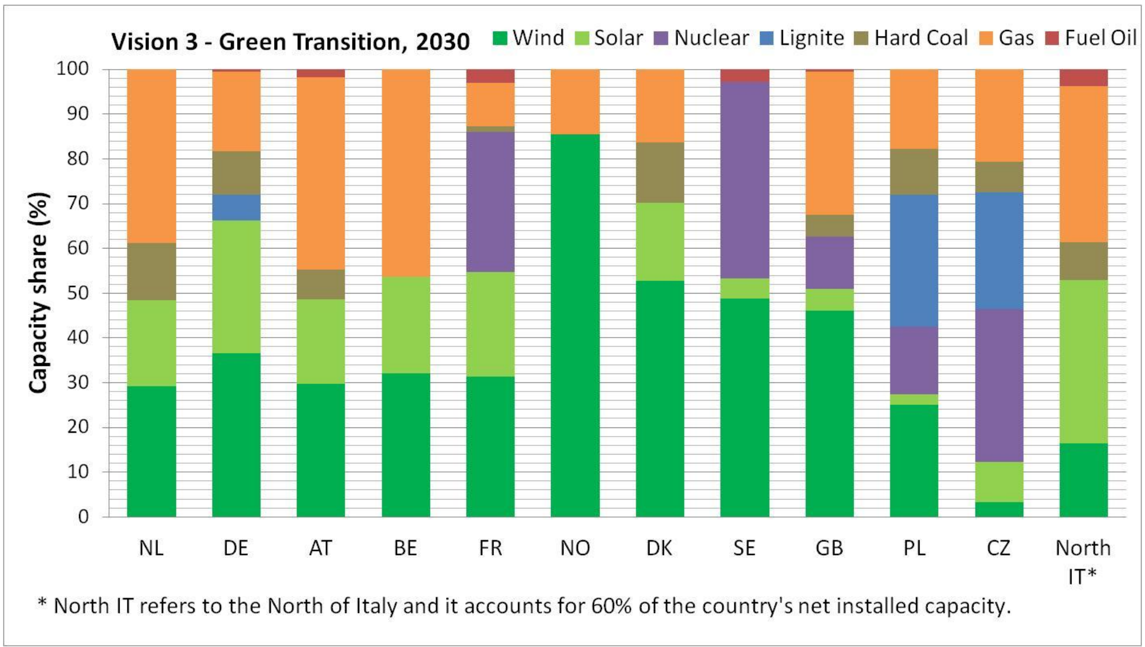

Figure B.2 . Breakdown of generation mix per country in Vision 3 year 2030

APPENDIX C

Demand parameter and assumptions

Table C.1. Annual percentage increase of demand (%) applied in scenario EU 2020.

	Netherlands	Germany	Austria	Belgium	France	Norway
Increase of the gross final energy consumption in the electricity sector from 2014 to 2020 (%)	5,3	-5,43	10,65	9,03	1,38	0,45

Note: For the additional energy efficiency scenario. Own calculation from the ECN database.

	Denmark	Sweden	Great Britain	Poland	Czech Republic	Italy
Increase of the gross final energy consumption in the electricity sector from 2014 to 2020 (%)	1,03	0,93	1,25	13,18	10,11	2,92

Note: For the additional energy efficiency scenario. Own calculation from the ECN database.

Table C.2. Adjustment of the demand in Norway (node i14).

Norway (node i14)					
Capacity (MW)	**Fossil Fuels**	**Wind**	**Solar**	**Total Capacity minus Hydro**	**Total Capacity (Thermal+RES+hydro)**
Scenario B 2014	1150	800	0	1950	32950
Scenario EU 2020	1300	2800	0	4100	37100
Vision 1 2030	855	2750	0	3605	41505
Vision 2 2030	855	2750	0	3605	41505
Vision 3 2030	855	5000	0	5855	44455
Vision 4 2030	855	11400	0	12255	64255

Table C.3. Adjustment of the demand in Austria (nodes i09 and i10).

Austria (nodes i109 and i10)					
Capacity (MW)	**Fossil Fuels**	**Wind**	**Solar**	**Total Capacity minus Hydro**	**Total Capacity (Thermal + RES + hydro)**
Scenario B 2014	8000	1900	400	10300	23900
Scenario EU 2020	8000	2600	320	10920	25020
Vision 1 2030	12156	3290	820	16266	35772
Vision 2 2030	11629	3290	820	15739	35244
Vision 3 2030	9500	5500	3500	18500	38606
Vision 4 2030	8856	5500	6500	20856	42592

Table C.4. Nodes list, latitude and longitude of nodes, provinces covered in each zone and population in each zone.

Node (Country - Zone)	Nodes	Latitude	Longitude	Provinces	Population
Netherlands					
NL - North	i01	52,79	6,26	Groningen, Friesland, Drenthe, Overijssel, Flevoland	3256276
NL - South	i02	51,61	5,48	1/2Utrecht, Gelderland,1/2North Brabant, Limburg	4995834,5
NL - West	i03	52,06	4,86	North Holland, South Holland, Zeeland, 1/2Utrecht, 1/2North Brabant	8527464,5
Germany					
DE - North	i04	53,28	9,99	Hamburg, Mecklenburg-Vorpommern, Schleswig-Holstein, 1/2Niedersachsen	10054081,5
DE - West	i05	51,81	7,96	Bremen, Nordrhein-Westfalen, 1/2Niedersachsen	22124526,5
DE - South	i06	48,87	11,73	Bayern, Sachsen, Thüringen	18811469
DE - South West	i07	49,84	8,53	Baden-Württemberg, Hessen, Rheinland-Pfalz, Saarland	21661787
DE - East	i08	51,97	12,40	Berlin, Brandenburg, Sachsen-Anhalt	8115599
Austria					
AT - East	i09	47,32	11,81	Vienna, Burgenland, Lower Austria, Styria, 1/2Carinthia,1/2Upper Austria	5879992,5
AT - West	i10	47,79	15,18	Vorarlberg, Tyrol, Salzburg, 1/2Carinthia,1/2Upper Austria	2619766,5
Belgium					
BE - North	i11	51,03	4,51	West-Flanders, East-Flanders, Antwerpen, Limburg, 1/2Flemish Brabant, 1/2Brussels	6408536,5
BE - South	i12	50,37	5,26	Hainaut, 1/2Flemish Brabant, Walloon Brabant, Namur, Liege, Luxembourg, 1/2Brussels	4691017,5
France	i13	48,11	3,49		65754000
Norway	i14	60,58	8,30		5109044
Denmark					
DK - West	i15	56,19	9,20	Nordjylland, Midtjylland, Syddanmark	3071110
DK - East	i16	55,52	11,77	Hovedstaden, Sjaelland	2588605
Sweden	i17	57,69	14,26		9 644 864
Great Britain	i18	52,16	-0,48		64100000
Poland	i19	52,87	16,98		38495700
Czech Republic	i20	49,71	14,15		10510719
Italy					
IT - North West	i21	45,35	8,66	Aosta Valley, Piedmont, Liguria, Lombardy	16130725
IT - North East	i22	45,68	11,47	Trentino-Alto Adige, Veneto, Emilia-Romagna, Friuli-Venezia Giulia	11654486

APPENDIX D

Generator properties, fuel costs and network parameters

Table D.1. Fuel costs according to type of fuel (€/MWh)

Nuclear	3.0
Lignite	4.40
Coal	12.70
Anthracite	12.70
Gas	38.70
Natural Gas	38.70
Light Fuel Oil	30.60
Heavy Fuel Oil	30.60

Table D.2. Fixed Fuel Cost according to fuel type (€/h).

Fuel type	Fixed fuel consumption (MThermie/h)	Random cost range for fixed fuel consumption cost (€/h)
Nuclear	0	10 - 30
Lignite	0.015	10 - 30
Coal	0.03	10 - 30
Anthracite	0.06	10 - 30
Gas	0.09	30 - 70
Natural Gas	0.09	30 - 70
Light Fuel Oil	0.08	30 - 70
Heavy Fuel Oil	0.08	30 - 70

The Fixed Fuel Consumption (MTh/h) according to the fuel type is used to specify an indicative cost range for the Fixed Fuel Cost (€/h). This means that it will be assumed that those fuel types like nuclear, lignite, coal and anthracite, which have lower fixed fuel consumption rates compared to natural gas, gas and light and heavy fuel oil, will also have a lower fixed fuel consumption cost.

In the same way as it was assumed with the fuel cost (€/MWh), random variability is introduced by using a cost range of fixed fuel consumption costs for each type of fuel. Table D.2 shows the cost ranges chosen for the calculation.

Table D.3. Operation & maintenance costs according to type of fuel (€/MWh)

Nuclear	1.2
Lignite	2.4
Coal	1.8
Anthracite	1.2
Gas	2
Natural Gas	1.2
Light Fuel Oil	1.2
Heavy Fuel Oil	1.2

Table D.4. Average operating efficiency according to type of technology (%)

Nuclear	30
Lignite	36
Coal	38
Anthracite	38
Gas	39
Natural Gas	50
Light Fuel Oil	39
Heavy Fuel Oil	39

Table D.5. Average startup costs according to type of technology (€/△MW)

Generation technology	**Direct Cost**	**Indirect Cost**	**Total cost**
Nuclear	35	0	35
Lignite-fired steam	28	55	83
Coal-fired steam	25	55	80
Anthracite-fired steam	25	55	80
Combined-cycle gas turbines	5	40	45
Gas-fired steam	33	40	73
Light & heavy fuel oil	33	40	73

Table D.6. Capacities of generating units according to fuel type for scenario B 2014 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	953,33		138,57	607,88	490
Germany	731,71	2124	150	569,2	1508,75
Austria				150	
Belgium				160	1186
France	346,67		571,43	90,63	3321,05
Norway				71,88	
Denmark	133,89		3,33	84,23	
Sweden	230		243,16	153,33	3300
UK	845,45		120,53	403,78	898
Poland	637,1	858		92	
Czech Republic	56,82	206,22	8	42,12	930
Italy	172,97		653,5	509,88	

Table D.7. Capacities of generating units according to fuel type for scenario EU 2020 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	770		138,5	612	490
Germany	623,17	1846	104,8	558,2	1000
Austria				150	
Belgium				184,2	1012
France	193,33		390,5	117,2	3315
Norway				81,25	
Denmark	68,33		48,67	80	
Sweden	100		121,05	116,7	3367
UK	707,3		52,1	412,57	898
Poland	635,8	809		220	
Czech Republic	48,2	210,5	10	52,2	930
Italy	188		582,5	524,9	

Table D.8. Capacities of generating units according to fuel type for Vision 1, 2030 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	869		0	396,94	484
Germany	701,8	1486,7	52,04	370,46	0
Austria				204,19	
Belgium				287,26	0
France	116		83,48	116,61	2947,37
Norway				53,44	
Denmark	162,5		0	134,85	
Sweden	0		34,74	0	3317,33
UK	174,14		26,53	638,95	1092,1
Poland	297,13	696		195	
Czech Republic	68,18	156,76	0	139,7	1300
Italy	235,34		89,74	553,58	

Table D.9. Capacities of generating units according to fuel type for Vision 2, 2030 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	869		0	394,33	484
Germany	701,81	1486,72	52,05	318,67	0
Austria				194,05	
Belgium				278,98	0
France	116		83,48	107,58	2947,37
Norway				53,44	
Denmark	162,5		0	123,5	
Sweden	0		34,74	0	2719,67
UK	174,14		26,53	582,17	1092,1
Poland	297,13	696		195	
Czech Republic	68,18	156,76	0	114,33	1300
Italy	235,34		89,72	531,14	

Table D.10. Capacities of generating units according to fuel type for Vision 3, 2030 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	869		0	485,7	0
Germany	551,98	1316,5	52,04	825,26	0
Austria				153,12	
Belgium				287,26	0
France	116		178,57	195	2105,26
Norway				53,44	
Denmark	148,78		0	124,31	
Sweden	0		34,74	0	3317,33
UK	264,45		31,89	513,58	1391
Poland	132,9	1181,7		713	
Czech Republic	68,18	156,76	0	139,7	1900
Italy	235,34		189,64	573,11	

Table D.11. Capacities of generating units according to fuel type for Vision 4, 2030 (MW)

Country	Anthracite + Coal	Lignite	Light + Heavy Fuel Oil	Natural Gas + Gas	Nuclear
Netherlands	770,17		0	461,03	484
Germany	451,79	1316,52	52,05	786,04	0
Austria				145,39	
Belgium				276,56	0
France	116		178,57	195	2105,26
Norway				53,44	
Denmark	148,78		0	124,31	
Sweden	0		34,74	0	3317,33
UK	264,45		31,89	513,58	1391
Poland	132,9	741		713	
Czech Republic	54,55	156,76	0	136,36	1900
Italy	204,4		189,62	563,33	

Table D.12. Minimum generation according to type of technology (% of nominal output)

Nuclear	40
Lignite-fired steam	40
Coal-fired steam	38
Anthracite-fired steam	38
Combined-cycle gas turbines	33
Gas-fired steam	33
Light & heavy fuel oil	33

Table D.13. Upward and downward ramp limits according to type of technology (MW/h)

Nuclear	1000
Lignite-fired steam	40
Coal-fired steam	40
Anthracite-fired steam	120
Combined-cycle gas turbines	70
Gas-fired steam	80
Light & heavy fuel oil	130

Table D.14. Minimum online and offline times according to type of technology (h)

Nuclear	40
Lignite-fired steam	10
Coal-fired steam	6
Anthracite-fired steam	6
Combined-cycle gas turbines	2
Gas-fired steam	2
Light & heavy fuel oil	0.042

Calculation of the inductive reactances of the transmission lines.

To calculate the reactances in the per unit system, an impedance base Z_{BASE} is calculated by assuming a value for $U_{Nominal}$ and S_{BASE} for the whole network:

$$Z_{BASE} = \frac{{U_{Nominal}}^2}{S_{BASE}} = \frac{(400\ kV)^2}{2000\ MW} = 80\ \Omega$$

Therefore, the reference unitary reactance in p.u./km used for all lines equals to:

$$x_{average} = \frac{X_{average}}{Z_{BASE}} = \frac{0.27\ \Omega/km}{80\ \Omega} = 0.003375\ p.u/km$$

And using $x_{average}$, the real reactances in the model vary between [0.51, 2.03] p.u.