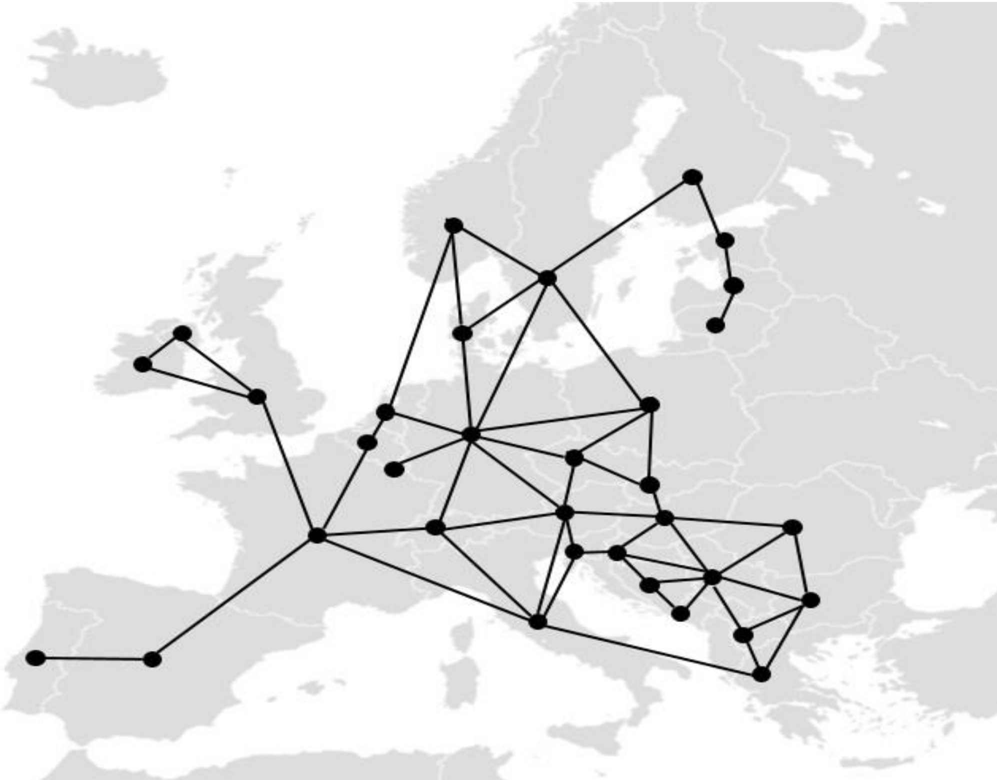

European Electricity Market Modelling: Studies on Grid Investment and Impacts of Renewable Energy Resources

Master's thesis in Sustainable Energy Systems

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Department of Energy and Environment
Division of Electric Power Engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2017

MASTER’S THESIS

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Master's Thesis in Sustainable Energy Systems
Rodolfo Silveira

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Cover: Grid representation of ENTSO-E member countries excluding Iceland and Cyprus. Each country is represented by a node.

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Abstract

In order to mitigate greenhouse gas emissions and be less fossil-fuel dependent, European countries have been increasing the use of energy from Renewable Energy Sources (RES), following ambitious targets defined by the European Commission and by national efforts. Consequences emerge in terms of grid investment and in the energy market price. The objectives of the thesis are to assess the impacts of large-scale integration of RES on the European power system on the increased transmission capacity requirement and the changes in market prices. The thesis also tries to identify best alternatives for investment in transmission interconnection capacity.

In order to achieve the above objectives, the following were carried out in the thesis. Firstly, a base case scenario (2015) is defined by collecting most recent data on the existing loads, generation and interconnection capacities, as well as production costs for the different countries and different generation technologies. Secondly, future scenarios were defined for 2030 and 2050 considering the EU targets for generation capacity and future load forecast. Then, an electricity market model was developed based on a DC Optimal Power Flow (OPF). The model has been used to analyze the European market for future scenarios and interconnection transmission capacities between various countries. A Cost-Benefit Analysis (CBA) method is applied to identify critical paths (most congested power lines) and rank the best investment alternatives in transmission capacity reinforcements between the European Network of Transmission System Operators for Electricity (ENTSO-E) member countries. The benefits are defined by the avoided congestions costs, and the costs are the annualized investment costs. To see if the investment is profitable, a cost-to-benefit index is used.

Simulations start with the base case scenario and proceeds to the future scenarios. Alternatives for transmission capacity expansion for the future scenarios have been evaluated and the future development of Locational Marginal Price (LMP) considering the different vision scenarios have been analyzed. Reinforcement connections in transmission capacity were proposed for many countries depending on the future horizon year. In 2030, proposed reinforcement interconnections include Norway-Netherlands, Austria-Italy and Switzerland-Germany, of 5784 MW, 4000 MW and 3540 MW respectfully. For 2050, the number of proposed reinforcement interconnections is higher due to the significant increase of the share of RES in the generation mix. Yearly investment costs for transmission capacity of the ENTSO-E system varies from €4 up to €11 billion of dollars, for 2030 and 2050 alternatives respectfully. Countries highly dependent on fossil-fuels in the generation mix such as Netherlands, Belgium and United Kingdom present the higher electricity price most of the scenarios analyzed, reaching average prices of €90/MWh or higher. Since demand for electricity is expected to increase for the future (i.e. due the increase of use of electric vehicles and heat pumps), grid reinforcement is expected, also because of the high penetration of solar and wind power in the Net Generating Capacity (NGC) system. Due to low running costs of RES, LMPs are in most cases affected in the sense of bringing electricity prices down when a large time horizon is considered. In some scenarios, depending on economic situations assumptions, the running cost of

the RES is considered to be higher than that of conventional hydro and nuclear, in some countries.

Key words: DC-OPF, Renewable Energy Resources, Locational Marginal Price, Net Generating Capacity, Net Transfer Capacity, Investment in Transmission Capacity.

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Preface

In this thesis, the project was started in middle of January 2016 with the planning phase, consisting of the description of all stages. All tests and simulations have been carried out in the laboratory for Master Thesis students in the Division of Electric Power Engineering at Chalmers University of Technology. Significant part of the work was spent on the data collection, to make them as reliable as possible, and on the model development.

I give special thanks to Dr. Tuan Le, as my supervisor and examiner for all the thesis period, and the weekly meetings as a constructive feedback progression. I would also like to thank my course colleague Jelte Hipp for his contributions with the GAMS code model and important transmission lines data.

It should be noted that the simulations could never have been conducted without the support of high quality and professionalism of the laboratory technical and administrative staff.

Göteborg August 2017

Rodolfo Silveira

Symbols

Variables

T	Power flow transferred from bus i to j.
P	Active power generation from bus i.
δ	Voltage angle at bus i.
TOC	Total system Operational Costs.

Parameters

AC	Actual transmission capacity reinforcement.
ACC	Avoided Generation Costs.
B	Susceptance.
CF	Capacity Factor.
$CGen$	Operational Cost of Generation.
CRF	Capital Recovery Factor.
IC	Investment Cost.
IC_0	Initial investment cost.
IC_K	Annualized hourly investment cost.
PD	Power Demand.
P_{MAX}	Maximum capacity of generation.
$Pwind$	Wind active power output.
$Profile$	Wind capacity profile in hourly resolution.
T_{MAX}	Maximum active power transfer.
TC	Transmission capacity reinforcement proposed.
π	Locational Marginal Price.

Sets

i	Bus i.
j	Bus j.
$plant$	Generation power plant technology type.
t	Time in hours.

Abbreviations

AC	Actual Reinforcement
ACC	Avoided Congestion Costs
AEC	Avoided Environmental Costs
BCI	Benefit-to-Cost Index
CBA	Cost Benefit Analysis
CC	Congestion Costs
CCS	Carbon Capture and Storage
CF	Capacity Factor
CRF	Capital Recovery Factor
CSP	Concentrated Solar Power
DG	Distributed Generation
DSM	Demand Side Management
EMMA	European Electricity Market Model
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	Europe Union
EVs	Electric Vehicles
FLH	Full Load Hours
GAMS	General Algebraic Modelling System
HP	Heat Pump
IC	Normalized Investment Cost
LMP	Locational Marginal Price
LP	Linear Programming
n	Number of circuits to expand
NGC	Net Generating Capacity
NTC	Net Transfer Capacity
O&M	Operation and Maintenance
PV	Photovoltaic
RES	Renewable Energy Sources
TC	Reinforcement Capacity proposed
TC1	Transmission Capacity before expansion

TC2	Transmission Capacity after expansion
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UNCCC	United Nations Convention on Climate Change
VRE	Variable Renewable Energy

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1 Introduction

1.1 Background

The European Parliament required an aim in 2009 for European Union (EU) countries to fulfil at least 20% of its energy demand from renewable sources by the year of 2020, and at least 60-80% by 2050 [1]. The achievement is to be done through individual national efforts. The human contribution for the climate change, through the greenhouse gases emissions (especially CO_2), is not the only matter to be faced. Concern for security of supply and less dependence on fossil fuels resources are tendencies of the upcoming years. Solar and wind power capacity are particularly growing fast. The European power system will be expected to face major challenges in the future due to intermittent and geographical nature of generation from RES. Normally, these challenges include the need for increased transmission capacity between countries and within countries in Europe, as well as the need for alternative back-up capacity and regulation capacity mechanisms in the power system. A grid planning model for the European power system is therefore required to analyse the different options for transmission investments and to investigate changes in the electricity price in future scenarios.

1.2 Motivation

In order to reduce greenhouse gas emissions and be less fossil-fuel dependent, complying with the Kyoto Protocol and to the United Nations Convention on Climate Change (UNCCC), countries are encouraged to take actions due to the Renewable Energy Directive Policy rules. In this thesis, the measure focused is the increased use of energy from renewable sources [1] and its consequences in terms of grid investment and impacts created by the introduction of the RES in the market energy price. In this direction, this thesis demonstrates that there is a need of a new grid infrastructure and a value assigned to the investment. The preferences for low carbon technologies are driven by the falling costs of the RES options [2] and the fast expansion of wind and solar power as renewable alternatives. The introduction of solar and wind power and the gradual decrease of conventional generation sources affect the electricity prices. It is of interest of this thesis to investigate long-term electricity prices changes according to different future scenarios characteristics based on economic factors, policies, technology development and load forecast. LMP-based market pricing gives a clear market signal for investment in transmission [3].

The motivation to focus on the EU power system is that it is a highly interconnected system which is expecting a considerable penetration of wind and solar power generation for the next decades. Load and generation changes are handled by all units inside this system. Despite the EU power grid being highly interconnected, the dispatch and market operation of the electricity system are still not centralized. Even though not all EU member countries are part of the same common power market at the present, known as power pool, there is a future trend for the European power system to be more connected and operated in a coordinated manner. As a result, the whole system is not operated in an optimal centralized arrangement, although there are sub-regions highly integrated such as the NordPool area among Scandinavia and Baltic countries [4], and the European Energy Exchange (EEX) area [5] in central Europe.

1.3 Objectives

The objective of this thesis is to assess the impacts of large-scale integration of renewable energy resources in the European power system. The thesis will focus on:

1. Identifying the needs and quantifying the best alternative investments in the transmission capacity between European countries;
2. Analysing the long-term power market impacts (i.e. total system operating cost, transmission investment cost and electricity price) in different countries in Europe due to the Renewable Energy Directive Policy, for 2030 and 2050 year scenarios.

1.4 Scope

- Grid and market models are limited to the European Network of Transmission System Operators for Electricity (ENTSO-E) member countries. There are 35 member countries [6]. Cyprus and Iceland are excluded because they are isolated from the European integrated power system.
- In the market model, the energy price is represented as a reflection of the external costs of the production of energy. The introduction of renewable energy resources is analysed for the power system. Other systems such as transport system are excluded from the thesis as well as the influence in the fuel market.
- The starting point (base case scenario) considered is 2015, as this year is the latest reliable in terms of data on national renewable energy sources shares by country, and considering some assumptions that is further detailed in Chapter 2.
- The expansion horizon of renewable sources in the power system generation is limited to solar and wind power.
- The renewable penetration is considered at the production side, thus not at distribution level, requiring the equivalent investment in transmission which is compared with the base scenario existing power grid.

Figure 1 shows the 33-buses network where each ENTSO-E member country is represented by one node. Considering the influence of load size, generation and geographical position, Germany (DE) represents the slack bus, where the voltage angle is assumed zero, and it is then the reference country. The network is extracted from the current power grid, but it is assumed the same interconnections also for the future scenarios. It does not mean though that the transmission lines capacities necessarily remain the same for the scenarios, but that no extra connections between countries are created nor original ones are removed.

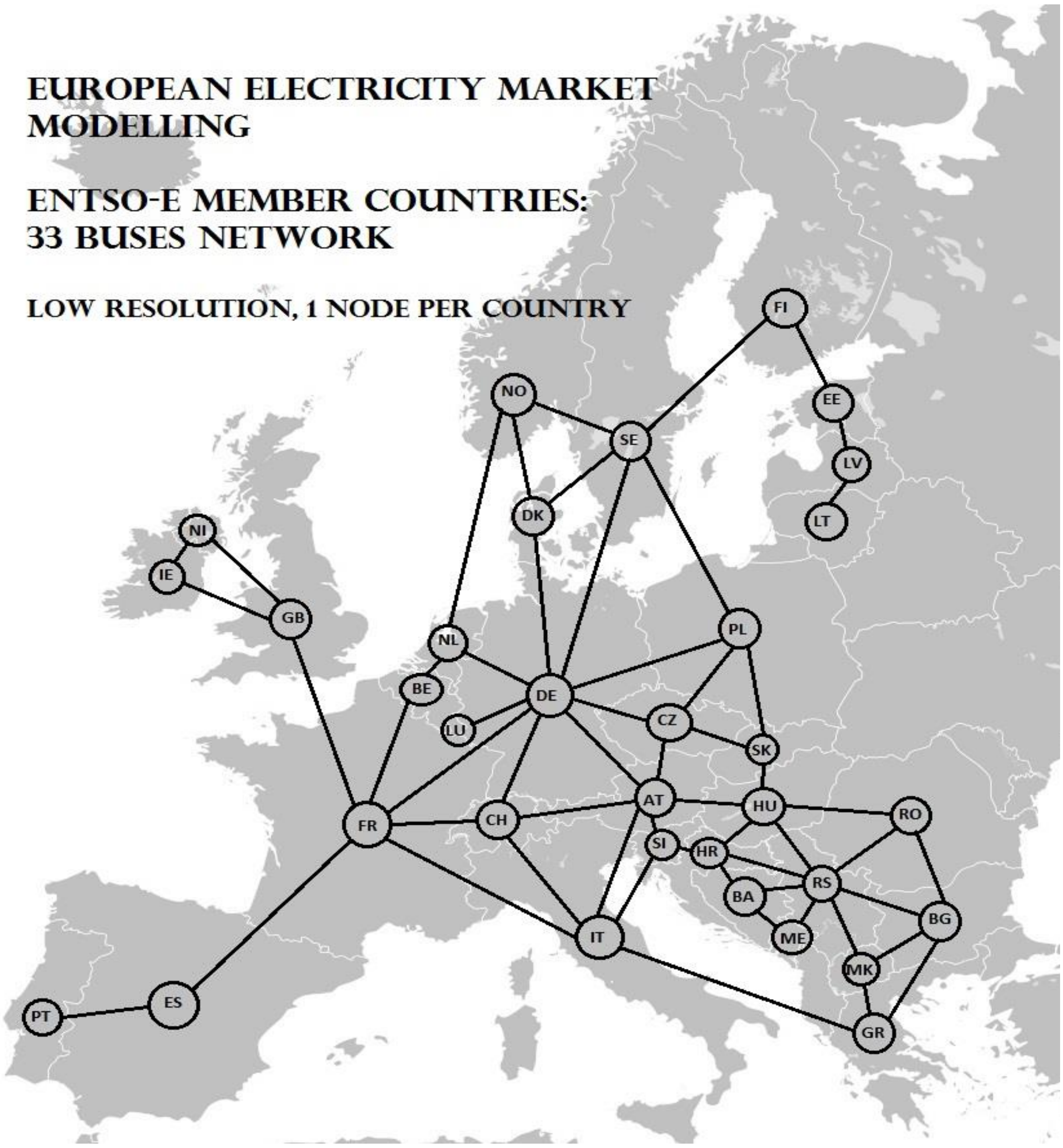

Figure 1 – ENTSO-E member countries 33 buses network excluding Cyprus and Iceland, simplified Grid Model

The full list of the ENTSO-E members and their respective Transmission System Operators (TSO) are found in Appendix A.

1.5 Main contributions

The main contributions of this thesis are listed below as compared with other relevant studies [7], [12], [15].

- Increased number of nodes (33 nodes resolution) [7].
- More updated data, base case scenario updated for 2015 [7], [12].
- New RES divided into wind and solar power [7], [12].
- Detailed price data for different generation between countries and future forecast [12].
- More detailed proposed investment alternatives options per scenario/vision. Congestion still is not relieved but fewer critical connections remain [15].

1.6 Thesis organization

The thesis report consists of 6 Chapters including the Introduction. They are described below:

- Chapter 2 builds a Literature Review offering a technical background of long-term transmission planning and electricity market modelling. Relevant previous studies on market-based transmission planning are discussed.
- Chapter 3 describes the model and the methodology behind it, including the optimization problem and its constraints. The concept of Locational Marginal Price (LMP) is presented. Planning process for transmission investment is detailed.
- Chapter 4 describes how the data is collected from different sources and countries, the assumptions and their consequences. Future scenarios are also described.
- Chapter 5 presents the simulations and results from the different scenarios. Analysis of the energy dispatch, electricity prices and total system running costs are presented. Investment alternatives for transmission capacity are suggested based on a Cost-Benefit Analysis (CBA).
- Chapter 6 draws relevant conclusions from the thesis and suggests directions for possible future work.

2 Literature review

In this chapter, relevant technical background is presented as previous studies done in the same field that contributed to the development of the thesis. They relate to: European electricity model, market value of RES, methodology for investment in transmission capacity reinforcement and future planning for the development of the European power grid as a common market.

2.1 Renewable Resources

Challenges from electricity power systems emerges from the increasing share of RES in the power generation sector [7]. RES technologies are intermittent, especially solar and wind power. Political decisions and societal changes create targets limiting the environmental impacts and following a society each day less dependent on fossil-fuel energy sources. But some countries go even further in their generation capacity plan, replacing nuclear power as well. For example, Germany represents the largest load aggregation node in this model and plans to phase out nuclear power completely by 2022, and increase the share of solar and wind power significantly to fill the gap. This means all future scenarios presented in this thesis, 2030 and 2050, considers no nuclear generation for the country.

An increase of RES if often correlated with a higher electricity demand. Due to the intermittent and random nature of wind and solar power, new technology development emerges to handle this variation on the electricity supply. Heat Pumps (HP) and Electric Vehicles (EVs) are examples of the shift of the power system towards systems using electricity. From 2030 to 2050 the final electricity consumption is expected to be 33% higher in Europe [8]. Demand Side Management (DSM) is an example of how consumers can handle their consumption behaviour and the load curve, to avoid higher costs at peak hours for example.

The deregulation trend of the power system contributes to a larger risk associated with decentralized market-based initiatives to invest in transmission separately from the generation expansion [9]. It is more complex to achieve optimal power flow solutions for a decentralized system, as many externalities such as generation external costs or redundant transmission flows are not detected by the model. It is a consequence that some misleading price signals from the Locational Marginal Prices (LMP) favour investments in some countries nodes over others [10]. During the transmission planning process some inputs such load, Net Generating Capacity (NGC) and operational production costs are the most uncertain [11].

2.2 Previous Studies

2.2.1 Electricity System Model

A master’s thesis in [12] models the European electricity market formed by the ENTSO-E member countries with focus on Denmark. The work is divided into two parts: first part is the electricity system modelling of Europe (low resolution for Europe and high resolution for Denmark), and second part studies a thermal electric energy storage system. The first part is particularly relevant to this thesis and thus will be discussed in this section.

A multi-node DC-OPF model is constructed as an optimal dispatch model where power is transferred by the cheapest generation available. A LP solver is utilised to minimize the total system costs. Market and grid data inputs are conducted from public data available from ENTSO-E and NordPool platform. The susceptance is calculated using the line length using the reactance to calculate the admittance. The admittance is the inverted impedance of the power line. The reactance constitutes the imaginary part of the impedance and the resistance is the real part (the resistance is neglected in the model and in this thesis). Virtual line length is computed by calculating the distance between geographical centres of neighbour countries buses, using Google Maps API query system. The model uses the LMP to represent the marginal nodal electricity pricing, as the demand is incremented by one unit. So the LMP is a sensitivity measure to represent the regional electricity price.

To manage system challenges created by the introduction of RES technologies in the power system, some possible solutions to soften the problems caused by intermittency and market value are divided into long-term and short-term measures. The study proposes a large scale electric energy storage situated close to the transmission grid, which helps to shave peaks of uncontrolled generation. For example, this is the case storage technologies handles the installed capacity of wind power when high winds occurs and bus exceeds the load and the net transfer capacity.

The electricity system model is first simulated without energy storage integration, comparing the LMP calculated and the spot price of electricity from NordPool. Values are similar and the deviation occurs mainly in the daily high peeks or deep valleys. One of the reasons is that NordPool wind power generation data does not include the curtailment effect of wind. Prices from the model are also found to be more stable compared to the actual market values because the ENTSO-E model act as an aggregated model, where all power plants from the same type of a considered country having the same cost characteristics.

2.2.2 The market value of variable renewable energy sources

The paper from Potsdam-Institute for Climate Impact Research and Vattenfall, Germany [13] discusses the market value of Variable Renewable Energy (VRE) sources. The value is affected by three technological properties:

- Supply of VRE is variable. Related to storage limitations and variability in supply and demand, electricity price changes with time. The value of electricity is affected by the time it is generated and by weather conditions.
- Output of VRE is uncertain. Forecast errors and uncertainties of VRE generation need to be balanced at short notice, which increase the costs thus reducing the market value.
- Primary resource is bound by geographical limitation. Since there are transmission constraints between regions, electricity is a heterogeneous good across space. Then, the value of electricity depends on where it is generated. Sites far from load centres reduced the value of VRE sources.

The European Electricity Market Model (EMMA) is a calibrated numerical model [13] used in this paper to address the optimal or equilibrium yearly generation, transmission and storage capacity and hourly market electricity prices for each market region. It covers a considerable geographical area (DE, BE, PL, NL and FR), using high quality solar and wind data, including technical constraints of the power system. EMMA is developed to estimate value factors considering different penetration rates of VRE sources under different policies and prices. The model minimizes total system costs with respect of investment and production.

Generation technologies are modelled as eleven different technologies with continuous capacity and they produce always when the price is above their variable costs. VRE generation is limited by hourly generation profiles. Demand is assumed price inelastic, assuming perfect and complete markets. Despite of curtailment of VRE being possible there are no costs associated to it, meaning that electricity prices cannot become lower than zero. Exchange power flow between areas are limited by the Net Transfer Capacities (NTCs) and interconnector investments are profitable if the social benefits prevail. The EMMA is modelled as a LP problem thus not a unit commitment model. Limitations of the model include absence of hydropower reservoir modelling and demand response. Technological change is not considered such as variation adaptability. Thus, ignoring flexibility aspects makes an overestimation of VRE market values and results can be considered conservative.

The paper finds that if a great share of VRE capacity is installed, electricity prices are reduced by the merit-order effect. Thus, the electricity value (i.e. per MWh) of VREs decreases as more capacity is installed. For wind power, its market value is slightly higher than the value of a constant electricity source at low penetration, but reaches values of 0.5-0.8 at a penetration of 30%. Solar power reaches a similar level with 15% of market penetration, because in this case the generation is concentrated in fewer hours. There are a number of integration options that help mitigating the value drop of the VRE sources: transmission investments, relaxed constraints on thermal generation, change in wind turbine design. Another conclusion is that VREs need mid and peak load generation as complementary balancing technologies, such as advanced natural gas power plants and biomass. However, base load technologies such as CCS or nuclear power do not go well with high penetration of VRE. High carbon prices are not enough to make solar and wind power competitive at high penetration shares and subsidies may be required for a period beyond 2020, thus decision makers should consider a limited role for wind and solar power regarding greenhouse gases mitigation.

2.2.3 CBA Analysis of transmission network reinforcement

A Cost-Benefit Analysis (CBA) is used in this paper [9] to evaluate an appropriate transmission planning strategy, with the costs being the investment in transmission capacity lines and the benefits the Avoided Congestion Costs (ACC) and the Avoided Environmental Costs (AEC). The attempt is to identify congestion points and propose a network reinforcement via investment of new transmission capacity. This study deals with the interaction of two projects, “Pathways to Sustainable European Energy System” at Chalmers University of Technology and “Towards future electricity networks” from the power systems laboratory at ETH Zurich. Increased generation from RES technologies and increase of electricity consumption in the transport sector imposes challenges.

The model consists of a 20-bus system based on a DC-OPF model, with focus on the interconnections between the nodes rather than connection nodes within the countries. Base case scenario considered is December of 2007. Load is considered inelastic, so the merit-order curve for the model is considered showing price as a direct response of the demand. The methodology for the Benefit-to-Cost Index (BCI) model starts with no network reinforcements. To be profitable, the investment needs a BCI higher than 1. Permanent congestions are the final candidates for the grid expansion. For the investment plan, the BCI is calculated based on the benefits of ACC and AEC. A capital recovery factor is used to divide the present value into yearly costs.

The scenarios in this paper represent different proposed transmission investment alternatives. The scenario with the higher BCI proposes the following transmission investments connections [9]:

- DE-AT, 3000 MW reinforcement.
- SL-HR, 2000 MW reinforcement.
- DE-CZ, 4000 MW reinforcement.

BCI stands higher than 5 for both low and high CO_2 prices. In this study, ACC have an insignificant participation, despite the additional transmission capacity proposed, thus congestions are not relieved. But regarding environmental costs, the model shows that all proposed investment scenarios are profitable, except one with the low CO_2 price horizon.

2.2.4 Long-Term transmission planning considering reliability

In previous work, generation and transmission models have been combined in a Cost-Benefit Analysis (CBA) considering Avoided Congestion Costs (ACC) and environmental costs, to compare transmission lines investment costs alternatives. In [14] the authors add another indicator, which is the system reliability factor. The steps below define the methodology steps to investigate the transmission reinforcement assessment.

- Identification of congested interconnections based on the probability they occur.
- Calculation of the probability of unserved energy for each node for the cases when important lines fail.
- Calculation of probability of unserved energy one more time, but now considering the new transmission capacity reinforcement.

Optimization of the model is based on minimization of the total system costs and a DC-OPF [13] constrained by generation capability limits, transmission capacity limits and voltage angle limits.

For the selection of a transmission line proposed alternative the paper includes the avoided unserved energy costs. Unserved supply of electricity makes social costs to increase when a transmission line is unavailable for a period of time.

Future scenarios are based on precipitation level (affecting hydro power availability) and wind availability for specific countries. Study shows that some lines are permanently congested, regardless of the generation mix or load level. The line connections are: AT-IT, SL-IT, CH-AT, HR-SL, BG-RO and MK-GR.

In the final part, the study shows an example of network reinforcement and the impact of unserved load is analysed. The transmission line chosen is CH-IT with an initial investment of 3890 MW. Line capacity is gradually increased until the unserved energy stabilizes at half of additional transmission capacity beyond the initial investment. This balance represents a trade-off between investments in transmission costs against costs from unserved energy.

2.2.5 Ten-Year Network Development Plan (TYNDP)

The TYNDP [15] is a report which gathers information about grid development and elaborated by ENTSO-E as a important tool to achieve Europe energy targets, such as security of supply across the continent, sustainable development of the energy system with RES, integration and affordable energy for European consumers via a common market integration. The member countries of ENTSO-E submits their transmission and storage projects for the upcoming years, including the definition of the affected region and the transmission capacity requirements. TYNDP explores different future scenarios, and using a CBA analysis by using different future scenarios. A numerical quantification of the benefit assessment from all projects according to the CBA methodology uses definitions of RES integration, security of supply and socio-economic indexes. Besides, a stakeholder participation is possible due to the accessible results, even for non-ENTSO-E members TSOs or storage project supporters. Once the future scenarios have been defined the next step is to characterize the investment needs. An investment in transmission capacity refers to every concern on the regional grid which is of European significance.

Main aspects of generation mix in 2030 include [15]:

- New NGC is mostly RES, especially wind and solar power. The total capacity is expected to double or even triple by 2030.
- These capacities are concentrated mostly in Germany and in regions with favourable wind conditions such as Iberia and Italian peninsulas and by the North Sea countries.
- Hydropower is expected to increase between 20% and 40%, the most expected areas being the Alps, Iberian Peninsula and Norway.
- Nuclear phase-out in Germany (by 2022), Belgium (by 2025) and Switzerland (by 2034). All present nuclear units in the UK are schedule to be shut down and France plans to reduce their share of nuclear to 50% of the power supply by the year of 2025. 30-45 GW of nuclear power is expected to be shut down in total. However, 20-30 GW is expected to be brought to the system, mainly by UK and Finland.
- Combined shutdown of nuclear and fossil-fired units along central Europe increases the distance between generation and load centres, requiring more grid infrastructure to transport the electricity.

After the results of market and network studies, several bottlenecks areas have been identified for the European power system and thus requiring new transmission investment. Figure 2 shows their locations and their transfer capabilities to accommodate the likely power flows between them.

To understand the causes and effects of bottlenecks, they are categorized into three types [15]:

- Security of supply: when specific areas cannot be supplied according to quality standards.
- Direct connection of generation: introduction of new generation power plants; both conventional and RES.
- Market integration: different prices within and between price zones.

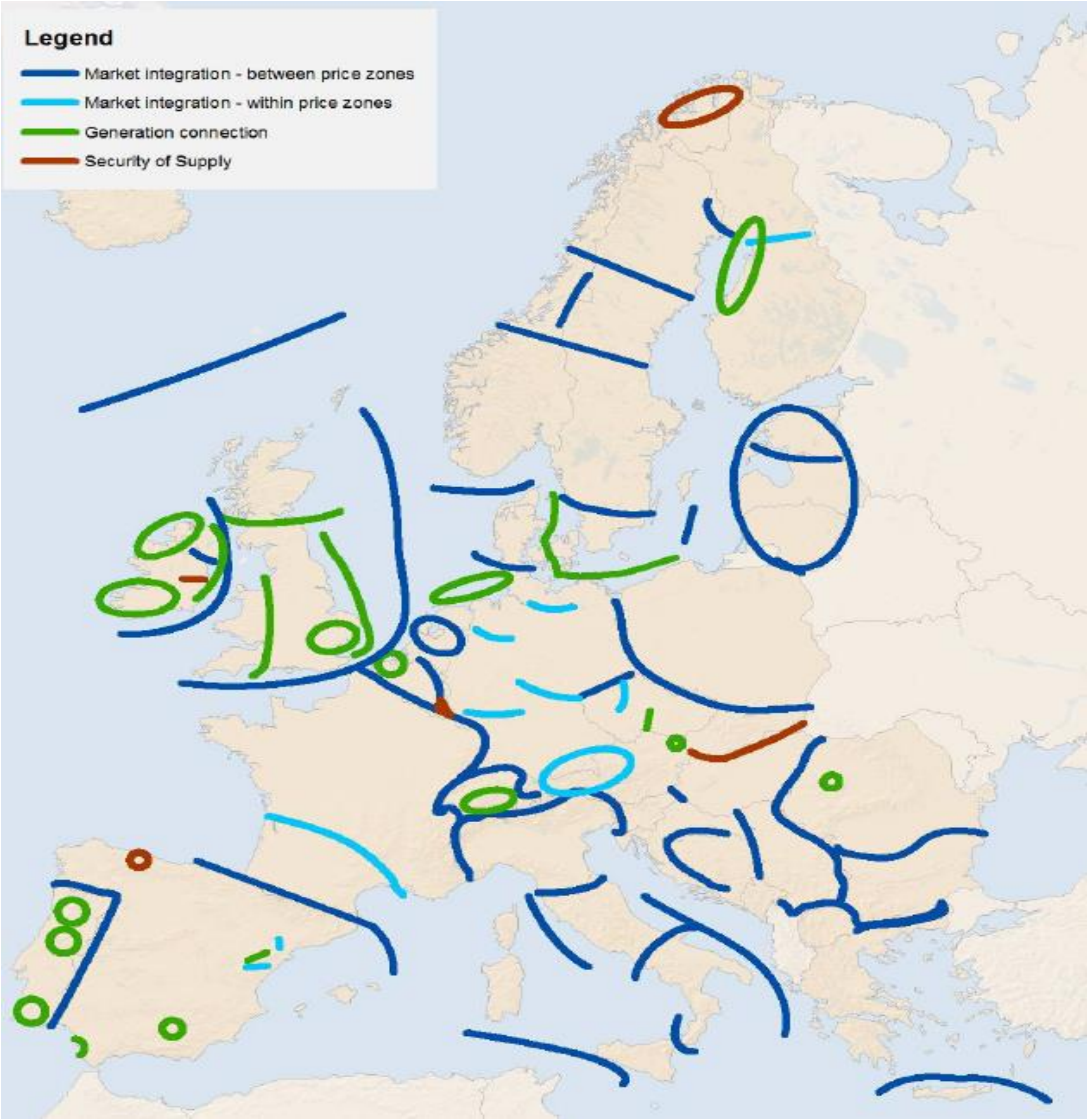

Figure 2 – Map of main bottlenecks in the ENTSO-E perimeter [15]

A pattern of very large power flow is explained by geography. Large RES areas emerge from Ireland to Denmark, along the North Sea shores, Iberian Peninsula and south of Italy. Densely populated areas such as England and north of Italy, along Mediterranean coastline from Spain to Greece, and in the main cities, import most of their electricity from neighbour areas. Hydro power pumping and storage in Scandinavia and the Alps works as a regulating power capacity with neighbour countries. Integration of RES is the main driver for system evolution in Europe. New wind power is planned in the North Sea and Baltic Sea regions (offshore) and inlands in the North (onshore). They are usually far away from urban centres and highly populated areas.

European transmission projects must match some criteria, including [15]:

- Main equipment is at least 220 kV for AC lines or 150 kV otherwise. It has to be located in one of the ENTSO-E member countries.
- Investments must contribute to an increase of transmission line capability across the ENTSO-E grid network or at its borders.

- NTC additional expansion must fulfil at least one of the minimum requirements below:
  - 500 MW or more of additional NTC is a minimum requirement; or
  - Connection of at least 1 GW / 1000 km^2 of generation capacity; or
  - Load growth is secured for ten years if the area has a consumption higher than 3 TWh per year.

The project profile in the TYNDP report amounts to approximately €150 billion, of which one third is for undersea cables. That is approximately equivalent to 2 €/MWh of electricity consumption in Europe over a ten year period and about 1% of the electricity bill for the final consumer.

3 Modelling and Methodology

This chapter describes the mathematical formulation of the EU electricity market model, the objective function and its constraints. The concept of LMP is discussed. The planning process for transmission investment is presented, based on a cost-benefit analysis.

3.1 Mathematical formulation of the Market Model

From the EU power system perspective, the load is treated in a configuration which each country is represented as a node. Due to the high number of member countries, it can be considered a low-resolution option. An aggregated model is created to represent the electrical transmission network of Europe. The demand is then available at all buses individually. At any node, eight different technologies for the production of electricity are assigned: hydro, nuclear, wind, solar, biomass, oil, gas and coal power. The Net Generation Capacity (NGC) is aggregated and assigned for each country (node). The Net Transfer Capacity (NTC) in the model represents the capabilities for all interconnections, also represented in an aggregated way.

In this type of modelling the DC-Optimal Power Flow (DC-OPF) model is suitable. The DC power flow method is a linearization of the full AC power flow method, which saves computational resources and time when compared with the AC method. DC model uses only active power flows, neglecting voltage levels, reactive power and transmission losses [17]. The resistance of each bus is negligible compared to its reactance and the magnitude of the voltage at every node is equal to its nominal value [18]. The method seeks to optimize an objective function and to satisfy all the constraints. In a power system, the power flow is described by the physical laws of electricity as known as load flow equations. Convergence of the objective function, which is the minimization of the total system costs, is checked at every stage of the process. This model is also applicable for long-time horizon expansion planning, guiding the investment decisions in the transmission system, proper for the transmission expansion planning model [16].

3.1.1 Objective Function

The objective function is the Total system Operational Costs (TOC) as presented in (1) which will be minimized subject to constraints described in the following sub-sections. It is the sum over every power plant, at every node *i* for each time *t*, associated with the cost of generation of each type of power plant for each node (country).

$$minimize\ TOC = \sum_{i} \sum_{plant} \sum_{t} CGen(i, plant) * P(i, plant, t) \qquad (1)$$

where, *P* is the active power from power plant production type at bus *i* and time *t*; *CGen* is the cost of generation. The *CGen* includes fuel and O&M (Operations & Maintenance) costs. In other words, it represents the running variable costs of each power plant type for a specific country.

3.1.2 Active Power Balance

At each node i (country), the active power balance must fulfil the power demand at the same node for every time *t* (2). The equation is also known as the demand-supply balance formula.

$$\sum_{plant} P(plant, i, t) - \sum_{j} B(i, j) * \delta(j, t) = PD(i, t) \tag{2}$$

Where: P = active power from power plant type at bus *i* and time *t;*

B = susceptance of the line;

δ = voltage angle of the line;

PD = demand at bus *i* and time *t*.

The set *plant* consists of eight different types of technologies: hydro, nuclear, wind, solar, biomass, oil, gas and coal power. Since demand is considered inelastic, the model is straightforward responsive to the load demand (*PD*). Thus, the objective function becomes a minimization of system operating costs problem [9].

Active power is transferred between two nodes according to:

$$P(i, j, t) = [\delta(i, t) - \delta(j, t)] * B(i, j) \tag{3}$$

The transferred active power P is constrained by the NTC of the power line connecting two nodes. The voltage angle at the slack bus (DE) is the angular reference, equal to 0º. Voltage magnitude is assumed 1 *pu* at all busses in the system.

3.1.3 Maximum Production

The power plants do not produce more than the maximum capacity, at every node *i* and every time *t*.

$$P(i, plant, t) \leq Pmax(i, plant) \tag{4}$$

$$P \geq 0$$

Pmax is known as the NGC value, acquired from the data extraction for each country and each power plant type. *P* is defined as a positive variable.

3.1.4 Capacity Factor (CF)

Power plants often do not operate at full rated power capacity all year round. The capacity factor is applied as a technical restriction for the RES technologies. Since wind and solar power are not always the cheapest technology available, they are dispatched according to their marginal costs following the merit order.

$$P(i, plant, t) \leq CF(plant) * Pmax(i, plant) \tag{5}$$

Then, the CF acts as a technical constraint, for each technology, to give the simulation more realistic results. A CF of 0.8 is assumed for all hydro power generation. For solar power, refer to Appendix C to see the *CF* correspondent to each country, using the Full Load Hours (FLH) method.

For wind power, a wind profile was used in an hourly resolution [19].

$$P_{wind}(i,t) \leq Profile(t) * Pmax(i) \quad (6)$$

At every node *i*, the wind power output P_{wind} is limited by the wind profile and maximum capacity for every hour *t*. Wind profile is assumed the same for all countries. Figure 3 shows the normalized value of wind power in an hourly resolution for 1 year.

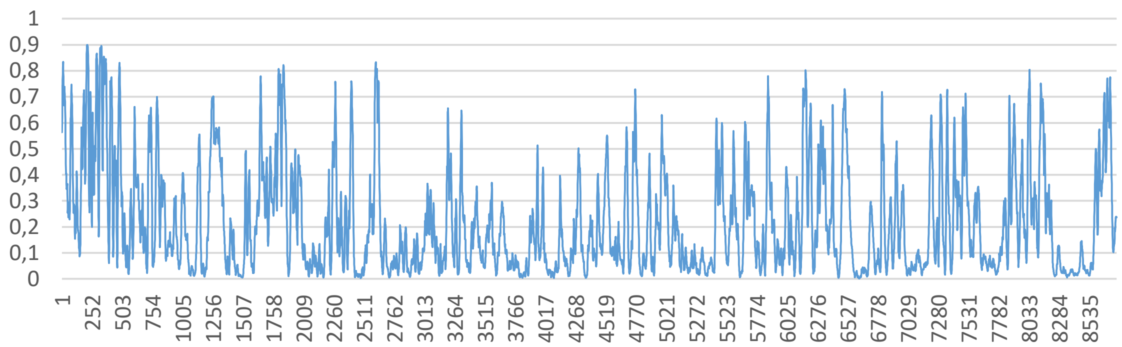

Figure 3 – Normalized value of wind power profile curve

3.1.5 Transmission Capacity Limits

At the transmission level, the power flow is limited by the maximum transmission capacity of the lines.

$$T(i,j,t) \leq Tmax(i,j) \quad (7)$$

$$T(i,j,t) \geq -Tmax(i,j)$$

where, *T(i,j,t)* is the power transferred from node *i* to *j* at period *t*.

3.1.6 Steady-state stability limit

Finally, for steady-state stability limit, the transmission angle differences between two connected nodes should be limited to $\frac{\pi}{2}$ rad.

$$\delta(i,t) - \delta(j,t) \leq 1.57 \quad (8)$$

$$\delta(i,t) - \delta(j,t) \geq -1.57$$

3.2 Locational Marginal Price (LMP)

Due to the different marginal operating costs of the countries analysed and their different power plants, the energy is exchanged between the areas in an economic way. In reality there are, however, physical and institutional constraints which will not permit an optimum economical dispatch as it would be in a free-market situation. Still, multi-area joint dispatch method will be used to model the generation coordination which objective function is to minimize total system cost [20]. The constraints to be satisfied in this model consists of demand-supply balance equations and transmission capacity limitations. The Locational Marginal Price (LMP) or nodal price is the cost of supplying an extra unit of load at the node *i* under consideration by the cheapest option available [18]. The LMP is determined by a combination of the generation costs of the marginal generation technologies.

$$\pi_i = MC(i) \tag{9}$$

Where π_i is the LMP at node *i*.

The LMP is calculated as a parameter from the output results of the model as a marginal value of dispatching one extra unit of power for a certain hour, associated with the active power balance equation, Eq. (2), where supply must fulfil the demand for all periods of time and for every node *i*. The eight generation source types are associated with a cost of generation and they are dispatched in a merit order. The LMP is expressed in €/MWh, representing the cost for each hour if the demand in node *i* is increased by 1 MWh.

Figure 4 below shows a simplified scheme of transferring energy from node *i* to *j*, constrained by the line capacity $Pij_{(max)}$.

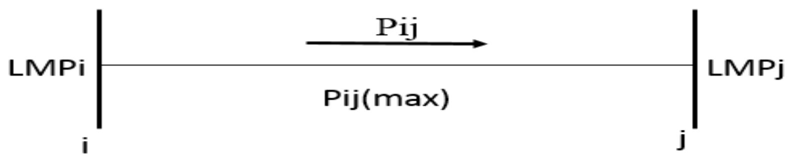

Figure 4 – Representation of the locational marginal price of two different nodes in a constrained economic dispatch

If there is no congestion, *LMPi* is equal to *LMPj*. However, if there is a congestion in this line, *Pij* is equal to $Pij_{(max)}$, and the LMP from node *i* and *j* are not necessarily equals and can be different. In this particular case where the energy is transferred from node *i* to *j*, if *Pij* is equal to $Pij_{(max)}$, *LMPi* will be lower than *LMPj*.

Economically counter-intuitive flows occurs when power flows from a higher price to a lower price region, and they are common especially in situations with three or more buses connected. This is because the laws of physics (Kirchhoff's voltage law) take place over the market laws. Increasing the line capacity does not necessarily will reduce the LMP of the node [18]. But the system as a whole will be operated more efficiently and the total system costs (variable costs) will be lower.

3.3 Investment in Transmission – Cost-Benefit Analysis (CBA)

The planning process for the decision for the investment in transmission is based on a cost-benefit analysis (CBA) that consists of operational (includes maintenance cost) and investment cost [7].

3.3.1 Benefits

The benefits of a proposed transmission line investment is connected directly with the amount of costs that could be avoided due, for example, congestion between lines.

$$benefits_k = ACC_k \tag{10}$$

where ACC_k stands for avoided congestion costs when an investment plan k is realized for a transmission line between the buses i and j. The congestion costs are calculated as the product of the nodal price difference between nodes i and j by the amount of power transferred between the two nodes. The method is used for congestion management in pool markets [21].

The ACC is calculated considering the Congestion Costs (CC) in Eq. (11).

$$CC_k = \sum_{i,j,t=1}^{nodes} \left(\pi_{i,t} - \pi_{j,t}\right) * P_{ijt} \tag{11}$$

If the nodal prices from the regions i and j are the same, the CC is equal to zero, meaning that there is no potential for saving costs investing in transmission for this specific time t. From the model, the CC are calculated as output results for every existing capacity interconnection between two nodes for every hour. The parameter is given in €/MWh and highest interconnections are ranked as candidates for reinforcement. Calculating the benefits from a new investment alternative, the ACC of an alternative is the sum of all reinforcement connections proposed. It is then calculated the hourly value so it can be compared with the hourly investment costs.

On the other hand, other costs can be included in Eq. (10), for example avoided environmental costs (AEC) related with external costs associated with emission of CO_2. In this thesis, those costs are directly included in the future scenarios, changing the *CGen*, see Eq. (1), increasing the costs of fossil-fuel generation technologies.

Before proposed CBA methodology is applied, it is necessary to identify the critical paths of the network. Critical paths are highly congested lines and lines transmitting large amount of power. The lines with high probability of being overloaded are promoted for reinforcement. In this thesis reinforcement means new transmission capacity for already existing transmission lines and not additional ones. Figure 5 shows the schematic for the CBA method used for proposing new investment alternatives between the countries.

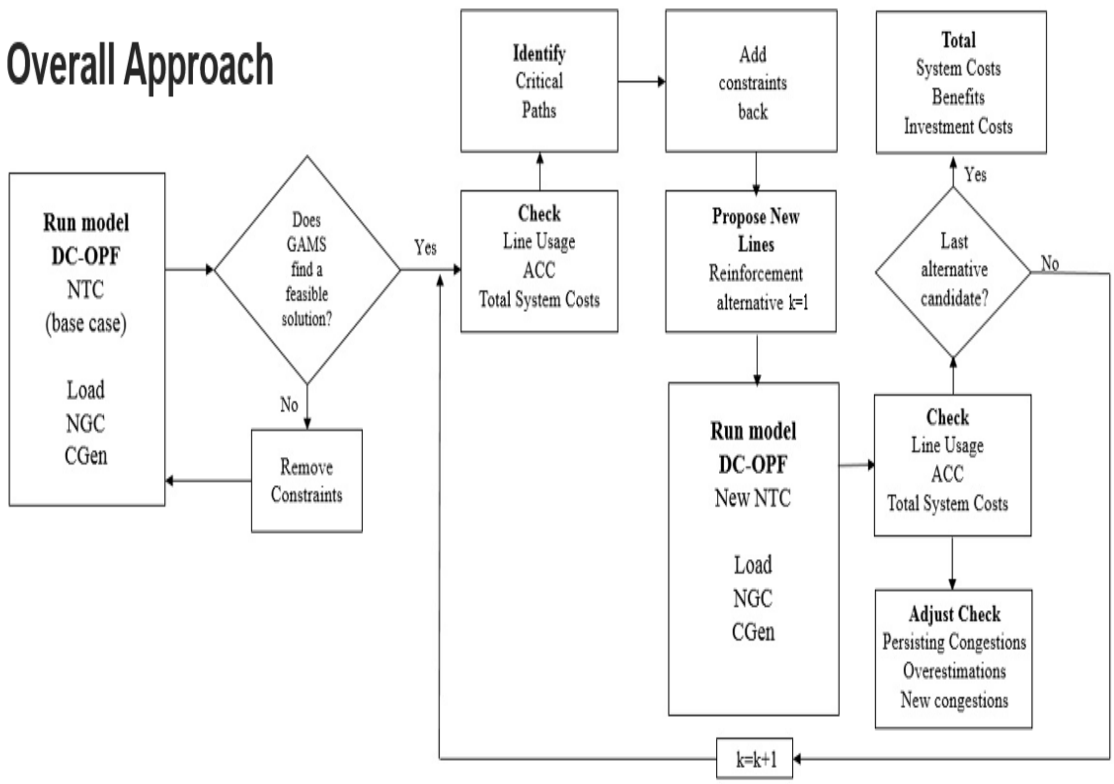

Figure 5 – Flow diagram method for investment alternatives using a CBA

For the cases the model cannot find a feasible solution, some constraints are removed in order to identify the bottlenecks of highest congestion and their persistence along a time period. Sometimes removing the line power flow limits constraints, Eq. (7), is not sufficient for the model to find a feasible solution. Then, other constraints can be removed, such as Capacity Factor constraints, Eq. (5), and Power transmission angle limits, Eq. (8). Then, the proposed interconnections are made based on how much lines connections are congested and the Avoided Transmission Costs (ACC) they represent. Permanent congestions are candidates for planning expansion. An adjust is made to review if some proposed lines are overestimated and suggesting investments above the necessary, to reinforce connections where the congestions persist or even to suggest new investments where new congestions appear. Proposing new lines based on the ACC of congested lines results in the reduction of the Total System Costs, i.e. the variable operational costs to run the entire system. If new proposed investments can be done keeping the same amount of Investment Costs (IC) or lower, the new system is being operated in a less-costly way.

The best alternative for the new NTC grid is used to run the model for a longer time period in order to find a better representation of the LMP effect and how it is affected by comparing the different future scenarios.

3.3.2 Costs

It is considered that the investment costs are proportional to the transmission capacity increase. Considering an initial Investment Cost IC_0, and TC_1 and TC_2 the Transmission Capacity before and after the expansion investment [7], the total investment cost is calculated as:

$$IC = IC_0 + IC_0 * \left(ln\frac{TC_2}{TC_1}\right), \quad TC_2 > TC_1 \tag{12}$$

The sum of all connection transmission lines gives the Total Investment Cost (TIC). An initial cost of 500 m€ per 1000km of transmission line is assumed, and an average distance of 1000km between countries. For the assessment of the investment plans a Benefit-to-Cost Index (BCI) is used:

$$BCI = \frac{benefits_k}{(1+r)^k * IC_k}, BCI > 1 \rightarrow profitable \tag{13}$$

Where IC_k is the hourly cost in the year k of the transmission line investment (IC), taking into account the number of years in the transmission project. If the BCI is higher than 1, the investment project is considered profitable. The hourly investment cost is calculated using a Capital Recovery Factor (CRF) which takes into account a number of years y for the investment project and a discount rate r [12].

$$IC_k = \frac{(IC * CRF)}{8760} \tag{14}$$

The CRF distributes a present value to annuities, according to the equation:

$$CRF(r, y) = \frac{r(1+r)^y}{(1+r)^y - 1}, years \tag{15}$$

4 Data Collection and Future Scenarios

4.1 Data collection

Data is collected from different sources mainly based on the ENTSO-E database and the specific Transmission System Operators (TSO) of each country. The transparency portal from ENTSO-E offers details regarding NGC per production technology type and more recent data.

As mentioned in Section 3.1, the eight types of power production considered in this thesis are: hydro, nuclear, wind, solar, biomass, oil, gas and coal power. Appendix D shows the NGC and the Cost of Generation (*CGen*) for each country and each technology. Missing values from ENTSO-E for specific technologies are found directly from the utility Transmission System Operator (TSO) companies of the countries.

The load data is collected fully for the months of January and July in an hourly resolution. Featured days include highest and lowest load days of the year.

The Net Transfer Capacity (NTC) values are extracted from ENTSO-E NTC matrix [6]. Last updated matrix is from winter 2010-2011. More up-to-date values are extracted from the ENTSO-E Transparency Platform [6]. Values of NTC for Scandinavia and neighbour countries are found at NordPool website platform [4]. Cyprus and Iceland are excluded from the data extraction because they are isolated from the European power system. The constructed NTC matrix of the power system is shown in Appendix B. Values of susceptance are calculated using reactance and line length from previous study mentioned in Section 2.2.1 of this thesis.

4.1.1 The process platform

The scheme below in Figure 6 shows what type of data is collected, how it is handled and transported to the optimizing tool GAMS.

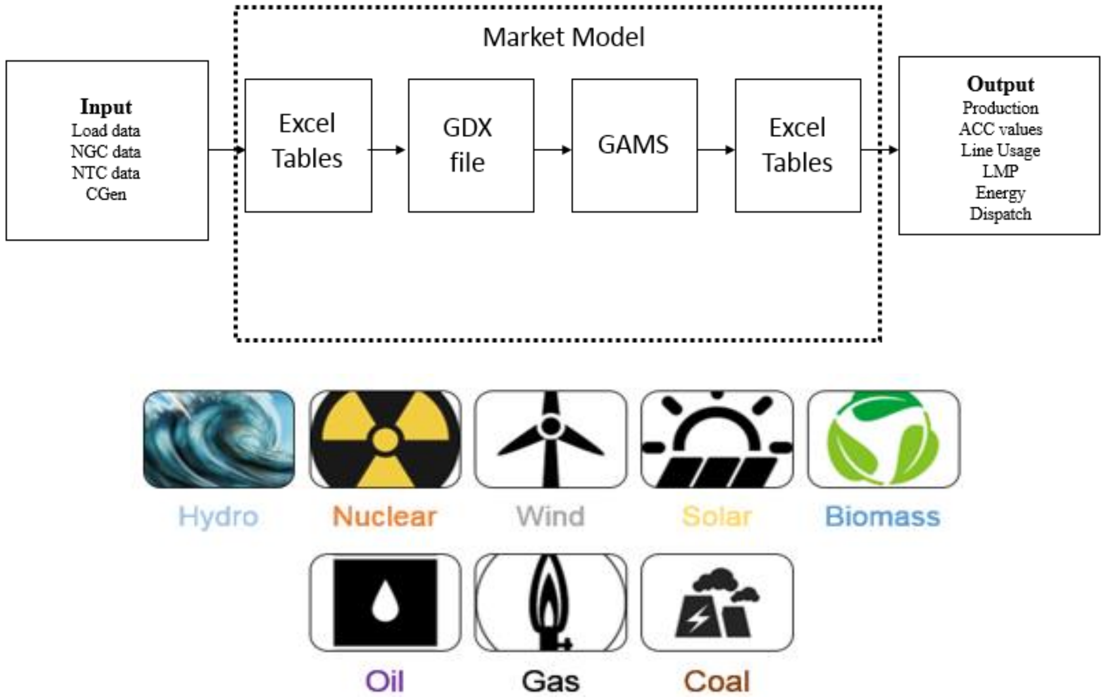

Figure 6 – Flowchart platform of Market Model simulation process

Data collected include:

- Load: in MW, hourly, from each country.
- NGC: in MW, for each country, for each generation technology type.
- NTC: in MW, for each transmission line connection between two countries.
- CGen: in €/MWh, for each country, for each generation technology type.

The input values are converted from excel tables to GAMS via GDX file, a function from the software to execute the data without necessity to include all data inside the model code. The results from the simulation are extracted and interpreted using excel sheets and tables. Relevant output include:

- Energy production: in GWh/h, hourly, from each technology type.
- Energy dispatch: merit order of technologies being used to produce power, based on minimization of total operation system costs.
- ACC: in €/MWh, hourly, for every power flow transfer connection between two countries.
- Line usage: percentage of use of a power line according to the power flow transferred and the maximum NTC allowed.
- LMP: in €/MWh, hourly, for every country.

4.1.2 About GAMS

The General Algebraic Modelling System (GAMS) is the chosen software for the modelling work in this project. This simulation tool is useful for large and complex problems, suitable for high-level modelling systems for programming and optimization. It is possible to change the formulation easily from one to another, including the constraints and models used [22]. The base code for the models is detailed in APPENDIX E. Large number of data input is possible to be added via Excel, as well as exported results, using the GDX tool.

4.1.3 Assumptions

Since the European power system is in reality very complex, some assumptions are made in order to simplify the modelling and still be able to answer the questions addressed to this project.

4.1.3.1 Market Modelling

The power system is driven by the laws of physics (power flow equations) and by human laws (market rules, policy instruments, public opinion etc.). To model the European electricity market, only active power is taken into account and there are no losses in any level of the grid, from the generation point to the demand. The DC power flow method is applied to simplify the power balance equation. Load, generation and transmission capacities are represented by aggregators. The problem is treated as a Linear Programming (LP) formulation which minimizes the total system costs. Market is perfect in the sense that the generation with lower price is always preferable first, the demand is inelastic and the system is dispatched in a centralized perspective. When congestion is taken into account, electricity price depends on the node in which power is being transferred [18] [23]. Thus, the price is the same for all consumers connected to the same bus.

4.1.3.2 Marginal Costs of Production

For the planning process, data collected such as marginal costs of production are not very reliable and thus are approximated. There are many methods to account for those costs, and this thesis focus on O&M (Operation and Maintenance) and fuel costs [24]. Nuclear power fuel costs include waste costs. In solar power, the type of technology assumed is residential solar PVs or large-scale concentrated thermal power plants (CSP), depending on the country. Wind power is assumed the sum of onshore and offshore technologies. O&M costs for onshore wind power is lower compared to offshore, due to higher costs including accessing and developing the maintenance of the wind turbines. Taking everything into account, O&M costs for wind power are expected to be somewhere between €0.027 and €0.054/kWh [25]. In this thesis, the cost of wind range varies from €14 to €36 per MWh for the base case scenario of 2015. Some vision scenarios for the future assume a more favourable economic condition and thus costs for solar and wind power are reduced by half for all countries. Still looking at the generation costs data, hydro power technology in consideration is large-scale. Finally, regarding oil power costs, the energy content of a barrel of oil is calculated as 5867946 Btu per Barrel of crude oil [26]. Comparing the energy content with the energy conversion to electricity, 10156 Btu/kWh for steam electric generators in 2014. This could lead to an overestimation since most of oil power plants are older than 2013. Crude oil barrel price is assumed to be €40 [27]. Summing up oil fuel price and its O&M costs, each unit of MWh of electricity generated will cost €106. The exception is Estonia (EE), which uses shale oil, at a cost of €80/MWHel.

4.1.3.3 Net Generating Capacity

Considering the Net Generating Capacity (NGC) data extraction, some simplifications are done. Total hydro power capacity is calculated as the sum of Hydro Water Reservoir, Hydro Pumped Storage and Hydro Run-of-river and poundage (ENTSO-E Transparency Platform). Coal power is the sum of fossil hard coal and fossil brown coal/lignite. Oil power is the sum of fossil oil and fossil oil shale. Gas power is the sum of fossil gas and fossil coal-derived gas. For the nodes Finland (FI) and Lithuania (LT), 1460 and 680 MW is added to the NGC. Those values are in reality imports from Russia, which is not part of the system representation. Considering that coal is on the margin, the values are added to the coal power NGC of the two countries.

All energy production technologies are assumed to be flexible and to be able to operate in part-load. There is no constraint in terms of ramp-up and ramp-down activation limits and costs, no must-run units and no part-load costs. Although this would sound unrealistic, in the long-term planning modelling perspective it is a reasonable assumption. Time step t is set to 1 hour.

The new RES (wind and solar power) modelling is simplified enough to get a seasonal and yearly reasonable outputs. A normalized wind profile is used to represent the normalized share of installed capacity of wind. Solar power output is limited by the time of utilization method and the respective capacity factor of each country.

4.1.3.4 Future Scenarios

For future scenarios (2030 and 2050) the load is considered affected by European economic conditions and the degree of integration on the energy roadmap defined by the European parliament. Estimations show that the growth of the electricity demand is balanced by the decrease in demand due to higher efficiency both in the production and demand side. No major changes in demand patterns are expected for human electricity activity in the next decades [28], but a load factor between 1 and 1.3 is used in the visions, depending on the economic conditions, RES penetration and technology development. In addition, demand side management is expected in the future to smooth out the demand curve thus reducing peak demand [29]. Fuel prices are assumed unchanged, following the idea that efficiency increased cancels out the increase of the fuel price [15].

4.1.3.5 Investment in Transmission Capacity

The reinforcement transmission lines have a minimum requirement capacity of 500 MW [15], and a maximum of 10000 MW, considering the whole transmission expansion project. Transmission initial investment costs are assumed as €0.5 billion for all connections (1000 km average distance for all connections and 500 k€/km). The interest rate *r* is assumed as 0.07 for all scenarios. Individual countries can invest a maximum of half of their total NGC in new transmission lines, and also a maximum of 10 times the already existing transmission capacity. Unprecedented transmission connections are not created.

4.1.4 Limitations consequences

Since this is a long-term transmission planning model, the modelling of wind and solar power production gathered from weather and geographical data for each specific node is not the focus, but may be a topic for future studies. Thus short-term temporal effects may not be observed in this analysis, because hourly information data such specific local wind and solar profiles are not used.

The capacity factor of each power plant for each country in reality varies a lot. Making assumptions and simplifications tends to underestimate the total system costs, mainly due to the cheap dispatch of hydro power. Limitations of water flow and weather conditions will affect the full load hours of each hydro power plant directly.

Cost data is of different generation technologies are estimated and have low accuracy. This data is less accessible to get and varies quite a lot from country to country and among the different power plant production types. For example, hydro power is cheaper when produced in Switzerland (CH) compared to Italy (IT), and coal power is cheaper in Germany (DE) when compared to France (FR) [9]. The increasing production of wind and solar power expected for the next years makes the cost of production to decrease, as a result of economy of scale. However, this effect is not detailed in this thesis.

Nevertheless, due to data uncertainty and unavailability, internal congested connections within countries are neglected. The thesis rather focus on inter-country connections. So, the detail resolution of the model is considered low for countries with diverse power system areas with different parameters.

4.2 Definitions of Study Scenarios

The following cases are considered in the thesis: Base case (2015), 2030 and 2050. The future scenarios are defined based on the Ten-Year Network Development Plan (TYNDP) report from ENTSO-E [15]. NGC tables for all future scenarios are found in the Appendix D. The six visions, four from 2030 and two from 2050, represent different policies regarding technologies, energy policies, economy and social development. The wide range of possibilities gives the report robustness and neutrality. Table 1 summarizes all six visions regarding their major differences compared with each other.

4.2.1 Base Case (2015)

The base case scenario consists of a single picture of the ENTSO-E system based on all 33 countries. The list of countries, values of NTC, NGC and generation operational costs are found in Appendix A, B, D1-A and D1-B respectfully.

4.2.2 2030 visions

There are four visions for 2030 which describes possible future scenarios rather than trying to make a forecast of the future. To guarantee a high level of certainty in the range described for each vision, extreme situations are avoided. In this thesis, the parameters taken into consideration include the NGC of each country, generation costs and load. Share of RES in the generation mix and CO_2 tax on emissions affect those parameters. The tax increases the generation costs for the fossil fuel based technologies. Economic conditions affect the cost of generation and technology development affect the load.

- Vision 1, Slow Progress: less favourable economic conditions, low share of RES in the NGC, low CO_2 tax, and low degree of load demand integration.
- Vision 2, Constrained Progress: less favourable economic conditions, low share of RES in the NGC, low CO_2 tax, and high degree of load demand integration.
- Vision 3, Green Transition: favourable economic conditions, high share of RES in the NGC, high CO_2 tax, and low degree of load demand integration.
- Vision 4, Green Revolution: favourable economic conditions, high share of RES in the NGC, high CO_2 tax, and high degree of load demand integration.

Figure 7 below summarized the 4 vision scenarios for 2030 defined by ENTSO-E:

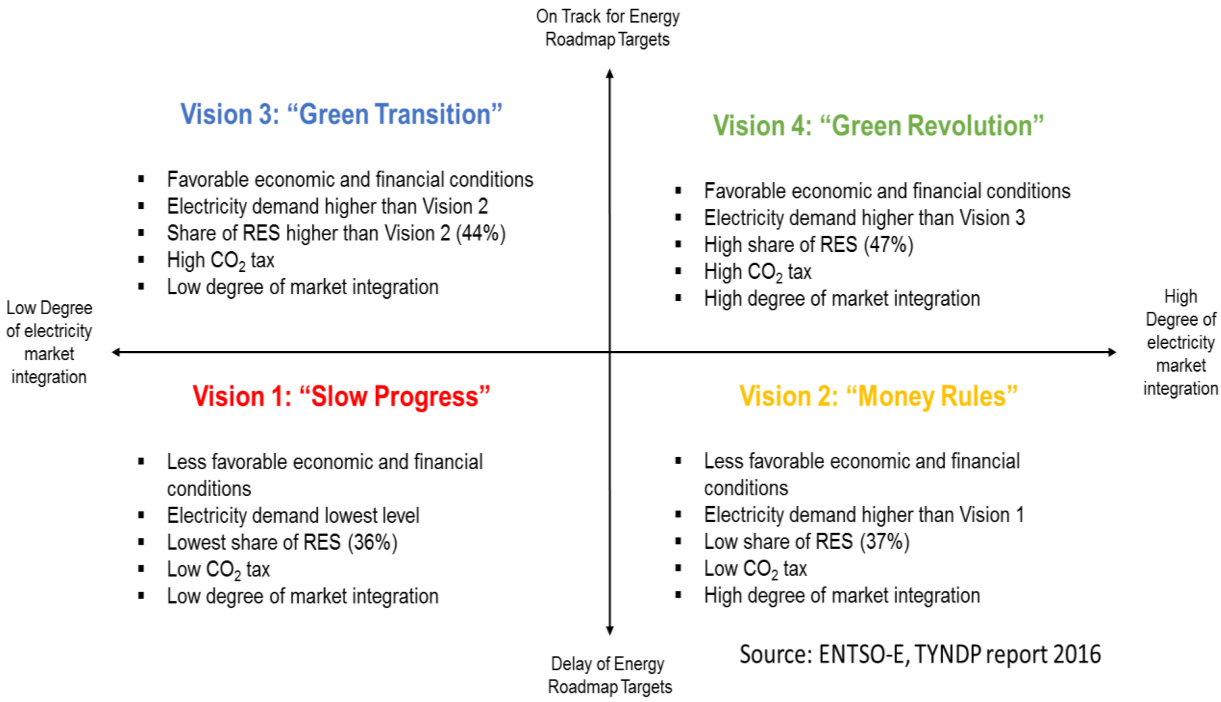

Figure 7 – Vision Scenarios for 2030 [15]

4.2.3 2050 visions

For 2050, two scenarios visions are presented, also based on the Ten-Year Network Development Plan (TYNDP) report from ENTSO-E [15]. The parameters taken into account include: electricity demand, RES share in the NGC, electricity exchanges and production on fossil fuels. The main differences in the electricity demand difference between the two visions are the change in electricity demand caused by electric heating, electric vehicles and energy efficiency measures [8]. Also, for both scenarios there is an extra exchange of electricity from North Africa, modelled as CSP.

- Vision 5, Large-scale RES: higher electricity demand, higher share of RES in the NGC, high CO_2 tax, and favourable economic conditions.
- Vision 6, Big & Market: lower electricity demand, lower share of RES in the NGC, high CO_2 tax, and favourable economic conditions.

The two visions from 2050 are represented in Figure 8 below.

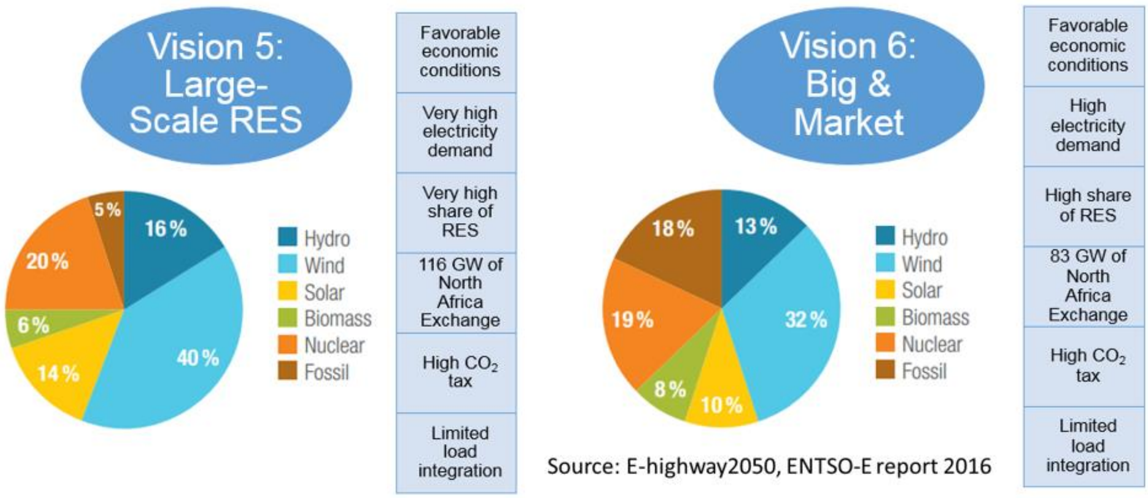

Figure 8 – Vision Scenarios for 2050 [15]

The model simulates different future scenarios and a sensitive analysis is done varying economic, political and technical factors described in Table 1 (Section 4.2). The LMP varies in respect of those factors and also on the time period interval the model is simulated. Factors listed in Table 1 affect directly or indirectly the load level, the NTC matrix, the NGC values or the cost of generation.

Table 1 – Comparison between all future vision scenarios with different parameters

Year	Vision	Economic Conditions	Electricity Demand	Share of RES	North Africa Exchange	CO_2 Tax	Load Integration
2030	Vision 1	less favourable	lowest level	36%	no	low	low
	Vision 2	less favourable	higher than vision 1	37%	no	low	high
	Vision 3	favourable	higher than vision 2	44%	no	high	low
	Vision 4	favourable	higher than vision 3	47%	no	high	high
2050	Vision 5	favourable	highest level	54%	116 GW	high	high
	Vision 6	favourable	lower than vision 5	42%	83 GW	high	high

In the next chapter simulations are done to investigate how these vision characteristics affect the LMP of the countries and the alternatives for investment in transmission capacity.

5 Case Study: Results and Discussions

In this chapter are presented the simulations and results from the different study scenarios. Analysis of the energy dispatch, LMPs and total system running costs are presented, discussed and validated with real markets values. Investment alternatives for transmission capacity are suggested and discussed based on a Cost-Benefit Analysis (CBA) and compared with the TYNDP report from ENTSO-E.

5.1 Base Case Scenario

5.1.1 Energy Dispatch

In this section it is shown how the model simulates the energy production dispatch of the 33 ENTSO-E member countries for the months January and July of 2015. This is an optimum scenario which minimizes total system costs (objective function), respecting the constraint inequations (see Section 3.1). The power plants are dispatched according to the merit order of each technology, which means cheaper technologies (in terms of operational running costs) are run first. Figure 9 shows the energy dispatch of all countries for the base case scenario, in January.

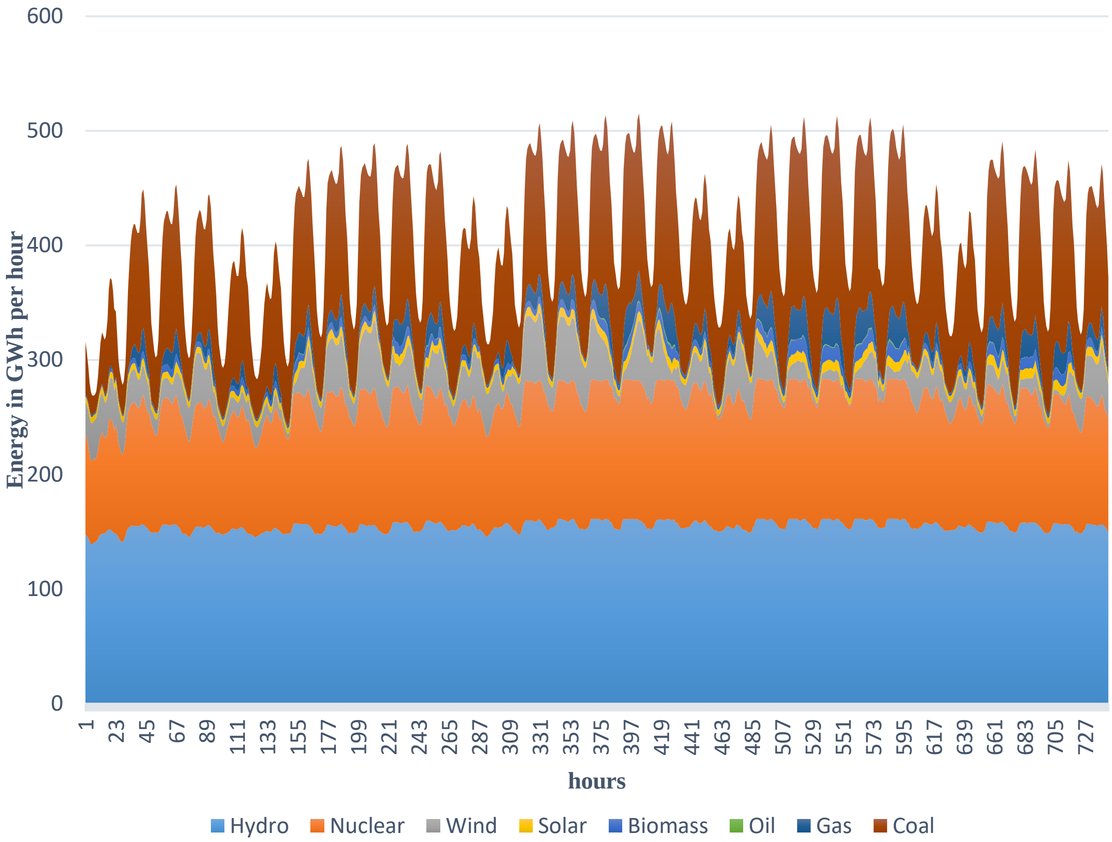

Figure 9 – Dispatch of energy production January 2015 ENTSO-E countries Base Case Scenario

Peak capacity production is around 510 GW at hour 400 and all eight generation types are dispatched this month for at least some hours. There is a small representation for the oil production (green) above the biomass production (blue) in the Figure 06. It can be also noticed that according to this model the electricity from coal power is acting as regulating power capacity, which is not true in reality. Start-up costs, part-load costs, ramp-up and down limitations and other constraints are not part of the model, then the technologies are constantly dispatched on a daily basis scale.

The simulation for the July month is represented by Figure 10.

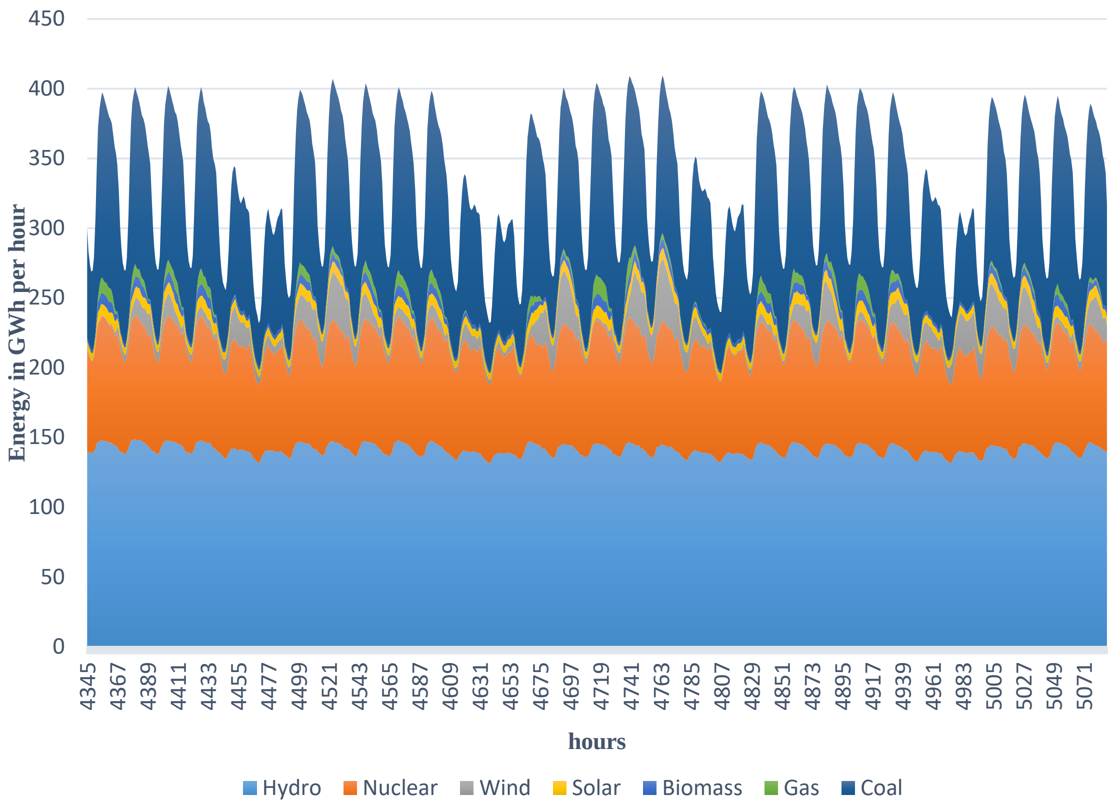

Figure 10 – Dispatch of energy production July 2015 Base Case Scenario

Since the load demand is overall lower in July, the oil power is not dispatched. Peak capacity is also lower at around 405 GW at the hour 4739. Considering that fossil fuel technologies have higher running costs, in July the Locational Marginal Price will be lower in average. Base load is predominantly dominated by hydro and nuclear power, which can be an overestimation since in reality the capacity factor of those technologies are lower than in the model.

Figure 11 shows how the energy dispatch is for Sweden (SE), base case scenario and January of 2015. The peak capacity is 28 GW for just 2 hours, where gas power is dispatched (the most expensive technology of SE). Coal and Oil power are not part of the Swedish generation mix so only the other 6 technologies are dispatched in the month with the highest load. It can be seen that the model is limited in the sense of simplifying how some technologies are dispatched. For example, in Figure 9 nuclear power (orange) is deviating quite a lot every day, which does not happen in reality. This is because ramp-up and down costs are not included in the model as well as part load costs operation. Incorporating those elements in the model would require a lot of processing and Linear Programing would not be enough to formulate the extra constraints.

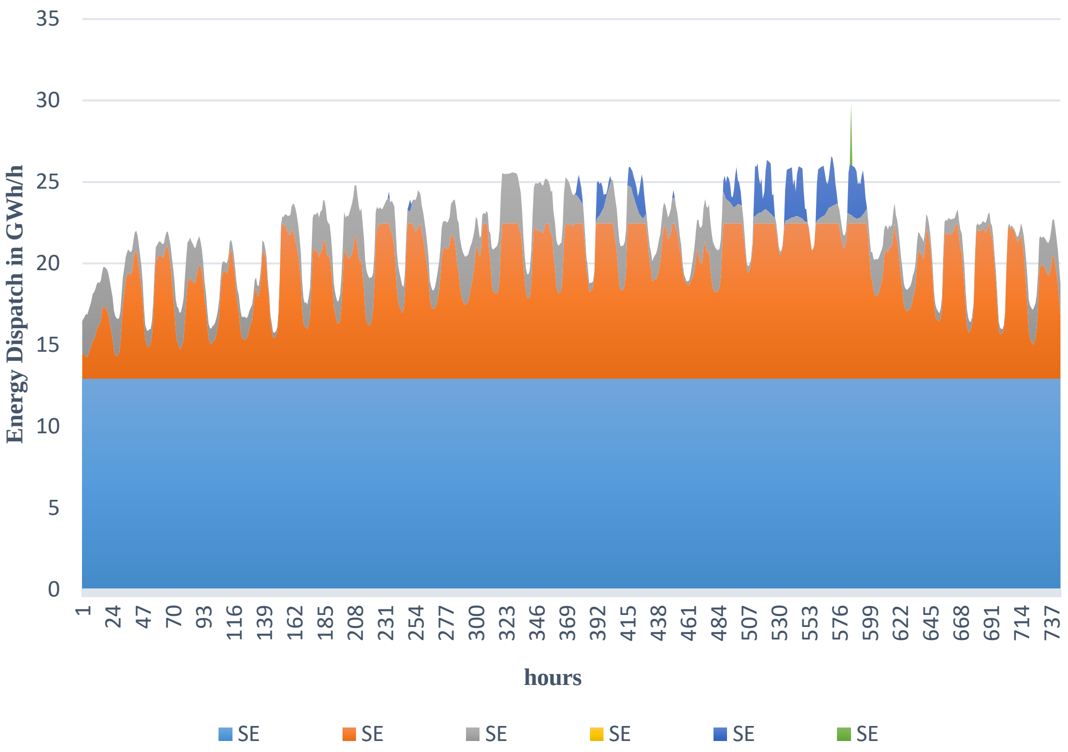

Figure 11 – Swedish Energy Dispatch Base Case Scenario, January 2015

5.1.2 Locational Marginal Price (LMP) – Base Case (2015)

The monthly average Locational Marginal Price (LMP) is plotted for each ENTSO-E country, for the months January and July, as it is shown in Figure 12. The LMP is dependent on some parameters such the energy mix of each country, the load level and available transmission with neighbour nodes. Countries high dependent on fossil fuel technologies (coal, gas and oil power) usually have higher generation production costs, thus having a higher LMP, and countries which can fulfil their demand with more RES have more chance of having a lower average LMP. Countries with only one transmission line connected have a LMP equal or very close from their neighbour countries. This is the case of Portugal (PT), Luxemburg (LU) and Lithuania (LT), which their only neighbour are Spain (ES), Germany (DE) and Latvia (LV).

The three highest LMP values for January are: GB (€68/MWh), NL (€63/MWh) and BE (€62/MWh). The lowest are: NO (€16/MWh), CH (€20/MWh) and SE (€26/MWh). Same simulations are done for the month July of 2015. The maximum LMP value is at €53/MWh, during peak hour. It can be noticed that the average value is lower for July. The maximum LMP value occurs at €60/MWh. The three highest LMP values in this case are: IT (€55/MWh), GB (€53/MWh) and NL (€50/MWh). The lowest LMP values are: NO (€15/MWh), SE (€18/MWh) and CH (€20/MWh). Figure 12 confirms that there is a considerable decrease in the LMP value in the summer month for most countries, except IT, Iberian countries, DE and LU. For CH, GR, NI and PL the LMP remains the same. IT becomes the most expensive region for July, and the Scandinavian countries NO and SE top the cheapest regions. The price is directly related with the electricity demand, which is higher in the winter for northern countries (heating demand) and higher in the summer for southern countries (cooling demand). Nevertheless, the trend is similar when compared with the winter time, and most of the countries present a decrease in the LMP.

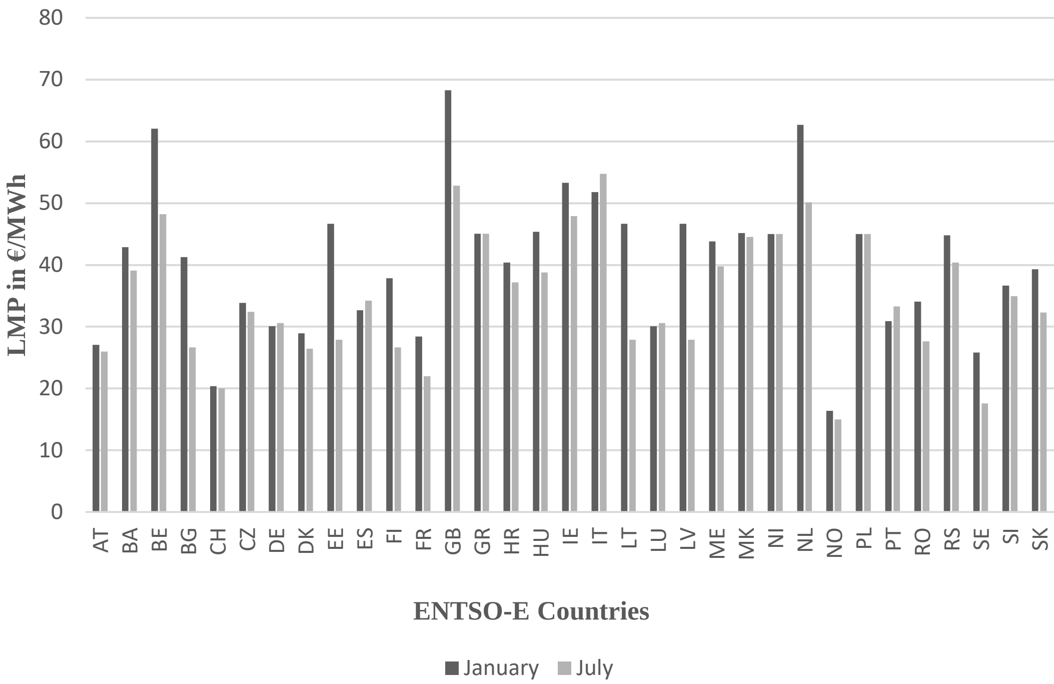

Figure 12 – Average LMP per country for January and July of 2015, Base Case Scenario

For a daily variation analysis, two cases are plotted: the day with highest load of the year (21/01/2015) and the one with the lowest load (05/07/2015). There is a considerable difference in the LMP daily variation (difference between maximum and minimum load) for January, 34%, from €35/MWh to €53/MWh. For June the daily variation is lower, 19%, from €28/MWh to €35/MWh. Figure 13 shows the LMP daily variation curve for January and July. When the system average LMP is considered, for all hours, the peak load day price is higher than the valley load day. The curve is highly correlated to the daily load demand.

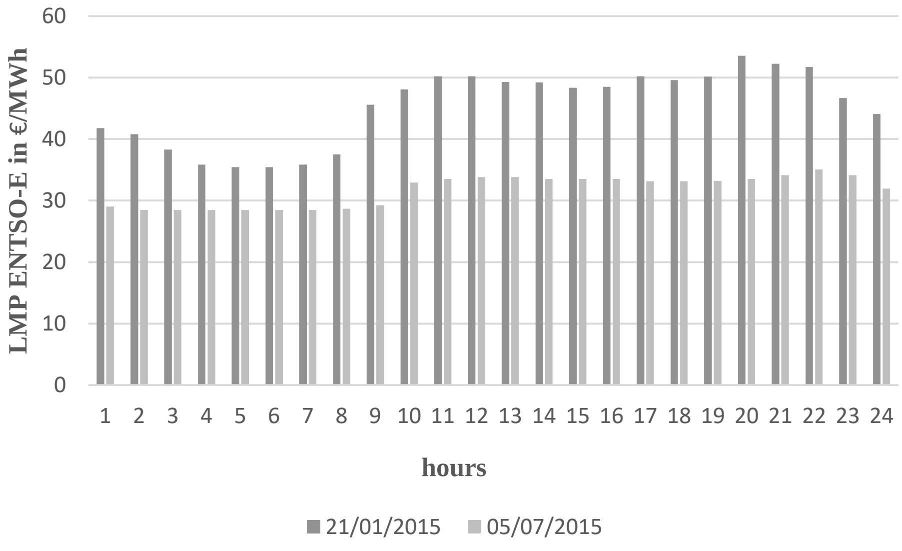

Figure 13 – Average ENTSO-E simulated system price LMP daily curve 21/01/2015, Base Case Scenario

Comparing it with real market values from the NordPool Elspot [4] and the European Energy Exchange [5] prices, the trend is similar, as showed in Figure 14. The NordPool system consists of the following countries: Norway (NO), Sweden (SE), Denmark (DK), Finland (FI), Estonia (EE), Latvia (LV) and Lithuania (LT). The EEX system is an international partnership, and the power spot market includes the countries: Germany (DE), Austria (AT), France (FR) and Switzerland (CH).

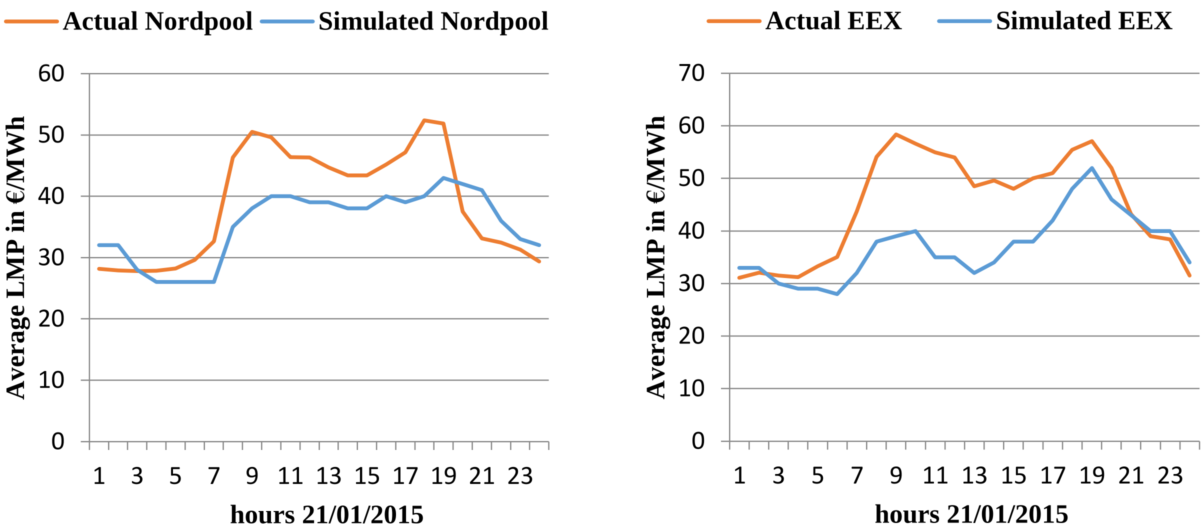

Figure 14 – Average NORDPOOL and EEX systems Elspot price daily curve 21/01/2015 [4],[5], compared with simulated prices

Important to notice that Elspot area price values for the NordPool and EEX systems represent market clearing price, based on the bids of producers and retailers or consumers. At the same time, the values extracted from the simulation of the base case scenario represent the operational costs in an optimized system which reduced total system running costs. Since the power market in EU is not completely central-dispatched, a good reference to see trends based on real market trade is the NordPool power market system. The spot market defines the short-term optimal trade between the market actors. The NordPool system Elspot average price for January 2015 is €34/MWh, and €11/MWh for July 2015 [4]. Monthly averages in the simulations tend to be underestimated due to the European centralized and optimum dispatch degree which does not occur in reality.

5.2 Investment in Transmission Alternatives

In Sections 5.2.1 and 5.2.2, the strategy for investing in new alternatives is discussed. Three first alternatives use a frequency of congestion method, and alternatives four, five and six incorporates ACC analysis in the process to rank the candidates for enforcement in transmission capacity. All transmission interconnection alternatives for 2030 use the Vision 1 scenario (see Section 4.2.1) for simplicity. In Section 5.2.3, both Visions 5 and 6 are tested, and the methodology for investing in transmission alternatives incorporate ACC analysis.

5.2.1 2030 Scenarios proposed alternatives

The first step is to remove the power flow transmission capacity constraint, eq. (7), to run the model with the minimum requirements. Then, some alternatives interconnection reinforcements are proposed based on the most congested lines and how often they are congested. For those lines, ACC analysis shows the connections where costs could be avoided if there was a higher capacity for the transmission line. For the 2030 scenarios, ACC analysis is done separately, after first three alternatives are proposed. Then the benefit of the investment is the ACC. The model runs in the time horizon of 24 hours for highest peak day of the year (21/01/2015).

Table 2 – Alternative 1 Based on unconstrained case

Alternative 1 - 2030	**Unconstrained case**					
Interconnection	TC1	TC	AC	n	TC2	IC
AT-IT	295	1475	1500	2	1795	2.8057
CH-FR	1100	1100	1000	1	2100	1.6466
CZ-PL	600	1800	2000	2	2600	2.4663
DE-CZ	1000	1000	1000	1	2000	1.6931
GR-IT	500	1000	1000	1	1500	2.0986
NO-NL	723	1446	1500	2	2223	2.1232
RO-RS	700	700	500	1	1200	1.5389
SE-DE	615	1230	1000	1	1615	1.9654
SI-IT	620	620	500	1	1120	1.5913
SK-PL	500	2000	2000	2	2500	2.6094

Where:

TC1: Transmission Capacity before expansion, in MW;

TC2: Transmission Capacity after expansion, in MW;

TC: reinforcement capacity proposed, in MW;

AC: actual reinforcement, in MW;

n: number of circuits to expand;

IC: normalized Investment Cost, see equation (12).

The first alternative (k=1) presents a high number of investment lines, a second one an intermediate option and a third alternative with fewer proposed investment line circuits. After first alternative is presented, adjust is based on the previous state alternative, and then a new one is suggested. Running the model with the NTC proposed in Alternative 1, the value of the Total Operational Costs (TOC) is €0.32145 billion. Using Eq. (13), (14) and (15) the BCI of 0.82 is calculated, for r=0.05 and y=30, meaning that the alternative is not profitable (lower than 1).

Alternative 2 is proposed based on a constrained case using the NTC proposed in the previous alternative. Now some congestions are eliminated, new congestion are created and some persist. Adjust is done in order to find a better cost-benefit alternative, selecting new candidates or resizing old ones.

Table 3 – Alternative 2 Based on constrained case considering persisting and new congestions from Alternative 1

Alternative 2 - 2030	**Constrained case considering persisting/new congestions**					
Interconnection	TC1	TC	AC	n	TC2	IC
AT-IT	295	2950	3000	3	3295	3.4131
AT-CZ	800	800	1000	1	1800	1.8109
CH-AT	1200	1200	1000	1	2200	1.6061
FR-BE	3400	3400	3000	3	6400	1.6325
GB-IE	530	530	500	1	1030	1.6644
NO-NL	723	4338	4000	4	4723	2.8767
SE-PL	600	600	500	1	1100	1.6061
SK-PL	500	500	500	1	1000	1.6931

Running the model with the NTC proposed in Alternative 2, the value of the Total Operational Costs (TOC) is €0.32100 billion and a BCI of 1.49, making it a profitable alternative. Alternative 3 is proposed following the same idea and it is based on Alternative 2. Again some congestions are eliminated, new congestion are created and some persist. Adjust is done in order to find a better cost-benefit alternative.

Table 4 – Alternative 3 Based on constrained case considering persisting and new congestions from Alternative 2

Alternative 3 - 2030	**Constrained case considering persisting/new congestions**					
Interconnection	TC1	TC	AC	n	TC2	IC
AT-IT	295	3540	3500	4	3795	3.5544
CH-AT	1200	1200	1000	1	2200	1.6061
CH-DE	4000	4000	4000	4	8000	1.6931
FR-BE	3400	3400	3000	3	6400	1.6325
NO-NL	723	5784	6000	6	6723	3.2298
SK-PL	500	500	500	1	1000	1.6931

The TOC is €0.32161 billion and the BCI lowers to 1.73, indicating that the alternative is profitable. A new strategy is used in the next section, and consists of using the ACC analysis to rank the highest congestion costs associated with the existing transfer interconnections.

5.2.2 Avoided Congestion Costs (ACC) Analysis

Coming back to the unconstrained 2030 case scenario, now the highest ten sum of ACC of all connections are listed. The proposed interconnections are based on the value of the ACC for the connections where the line usage is being constrained by the power flow maximum limit.

The values of the transmission capacities are listed in the Table 5 below.

Table 5 – Alternative 4 Based on unconstrained case, ranked by highest ACC values

Alternative 4 - 2030	**Unconstrained case**					
Interconnection	TC1	TC	AC	n	TC2	IC
DE-NL	3850	3850	4000	4	7850	1.7124
FR-BE	3400	3400	3000	3	6400	1.6325
NO-NL	723	1446	1500	2	2223	2.1232
CH-IT	4165	4165	4000	4	8165	1.6731
FR-GB	2000	2000	1000	2	3000	1.4054
SI-IT	620	620	500	1	1120	1.5913
AT-IT	295	1475	1500	2	1795	2.8057
CH-FR	1100	1100	1000	1	2100	1.6466
CH-DE	4000	4000	4000	4	8000	1.6931
GR-IT	500	500	500	1	1000	1.6931

For alternative 4, the TOC calculated by GAMS is €0.32045 billion and the economical parameter BCI is 1.53 (profitable). Keeping the NTC proposed by alternative 4, new congestion network is formed and adjust are made until alternative 5 is proposed.

Table 6 – Alternative 5 Based on constrained case considering persisting and new congestions from Alternative 4, ranked by highest ACC values

Alternative 5 - 2030	**Constrained case considering persisting/new congestions**					
Interconnection	TC1	TC	AC	n	TC2	IC
CH-AT	1200	1200	1000	1	2200	1.6061
FR-BE	3400	3400	3000	3	6400	1.6325
DE-SE	615	615	500	1	1115	1.5949
NO-NL	723	4338	4000	4	4723	2.8767
SE-DE	615	1230	1000	1	1615	1.9654
SK-PL	500	500	500	1	1000	1.6931
SE-PL	600	600	500	1	1100	1.6061
RO-BG	200	200	500	1	700	2.2527

TOC are reduced to €0.32095 billion and BCI in this case is 1.46.

Table 7 – Alternative 6 Based on constrained case considering persisting and new congestions from Alternative 5, ranked by highest ACC values

Alternative 6	**Constrained case considering persisting/new congestions**					
Interconnection	TC1	TC	AC	n	TC2	IC
CH-AT	1200	1200	1000	1	2200	1.6061
FR-BE	3400	3400	3000	3	6400	1.6325
DE-DK	2100	1050	1000	1	3100	1.3894
AT-IT	295	3540	3500	4	3795	3.5544
NL-NO	723	5784	6000	6	6723	3.2298
SK-PL	500	1000	1000	1	1500	2.0986

In the attempt to reduce the number of investment interconnections, alternative 6 end up increasing the TOC to €0.32095 and increasing the BCI to 1.61. Then, for the 2030's future scenarios sensitivity analysis, alternative 3 is assumed as the NTC matrix, adding connection DE-DK from alternative 6 for feasibility purposes since both countries present high penetration of RES in all scenarios, so the supply must meet the demand for all periods of time. Combine these alternatives to create a proposed investment for 2030, as detailed in Figure 15 and Table 8.

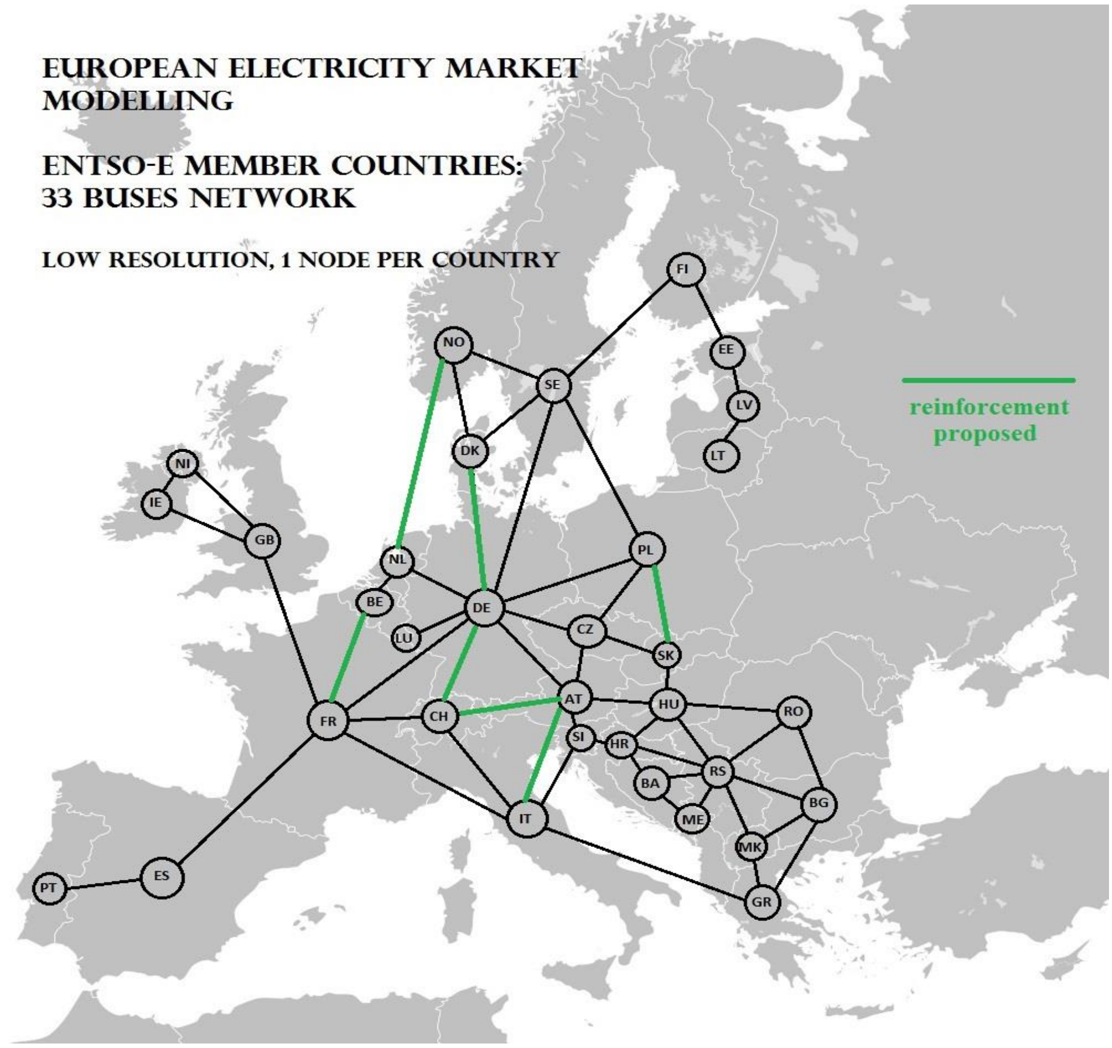

Figure 15 – Transmission reinforcement connections proposed for 2030

The green lines are the capacity reinforcement proposed for 2030. They are an increase of capacity of already existing interconnections (in this thesis no new extra connection is created). Some investment can be compared and validated with real future projects found at the TYNDP report (12) from 2014. Overall all the suggestions are plausible and realistic, and most of them are already addressed in the TYNDP report.

For the connection CH-AT and CH-DE, the project is called Swiss Roof, project 90, and its plan connects CH with both DE and AT. The expected date of commissioning is between 2017 and 2022 and the contribution is 1200 MW for the connection DE/AT (border area) with CH (Rüthi substation). FR-BE connection (project 23) presents a future project between Avelin/Mastaing (FR) substation and Horta (BE) substation. The expected date of commissioning is 2021 and since the project is in the planning phase there is no proposed NTC value presented in the report. Project 179 is a project between DE-DK and it is still under consideration phase, with an expected date of commissioning for 2030. No NTC value reinforcement is presented yet. For AT-IT, project 26 describe several connections between both countries. The project focus on supporting the power balancing between RES in Italy and pump storage hydropower plants in the Austrian Alps. The total transmission capacity proposed is 1770 MW, with the expected date of commissioning between 2018 and 2023. Projects varies from consideration phase, to planning and permitting. North Sea offshore grid infrastructure scheme (project 230) describes a complex and large project including several countries forming a ring: NO, GB, NI, IE, DK, DE, NL, BE, LU and FR. NO connects directly with GB and DE in this scheme. The path to DE is in permitting phase with a NTC of 1400 MW and the further connection to NL is still in planning phase. Due to this complexity of connections, not a simply direct connection between NO-NL, the value proposed for this connection is much higher than the one presented in the TYNDP. Also, in the thesis the lines are considered to be the same costs for all connections, while in reality deep subsea cables are more expensive. There is no planned interconnection between SK and PL directly according to the TYNDP report.

The market model is run for different future scenarios firstly operated without line transmission constraints. Then, using a cost-benefit analysis transmission capacity reinforcements are proposed, compared and validated with the TYNDP report from ENTSO-E. The Table 8 below comparing the proposed alternative with the actual planning projects of the TYNDP.

Table 8 – Comparison between proposed interconnections for 2030 and TYNDP final report from 2014

Interconnections - 2030	Proposed (MW)	TYNDP (MW)
AT-IT	3540	1170
CH-AT	1200	1200
CH-DE	4000	1200
FR-BE	3400	Planning phase
DE-DK	1050	Planning phase
NO-NL	5784	1400
SK-PL	500/1000*	No planned project

**difference between alternatives 3 and 6*

Total investment costs for the proposed alternative is €4.89 billion per year (annualized cost using CRF).

5.2.3 2050 scenarios proposed alternatives

For 2050 scenarios, two alternatives for Visions 5 and 6 are proposed (one for each vision) using the same strategy as used for 2030. The base case scenario now is the base NTC from 2015 adding the proposed alternative from 2030. It is called partially constrained case because the power flow constraints are removed but the new proposed connections from 2030 remain. Feasibility is still not reached since now there is a significant share of RES in the NGC mix in both visions, which implicates in larger reinforcements, both in terms of capacity and number of interconnections. Transmission flow constraints are removed so critical lines can be identified. Adjust is done and alternatives 1 and 2 for 2050 are proposed in the Tables 9 and 10 below, including the interconnections suggestions and requirements. Then, the total running costs and the economic index BCI is calculated for both cases.

Table 9 – Alternative 1 for Vision 5 Based on partially constrained values, ranked by highest ACC values

Alternative 1 - 2050	**Based on partially constrained values from 2030**					
Interconnection	TC1	TC	AC	n	TC2	IC
AT-IT	295	1475	1500	3	1795	2.8057
BG-RS	450	2250	2000	4	2450	2.6945
CH-DE	1500	1500	1500	3	3000	1.6931
CZ-DE	3650	3650	5000	5	8650	1.8628
ES-FR	1300	5200	5000	5	6300	2.5781
FR-BE	2300	2300	2500	3	4800	1.7357
FR-GB	2000	4000	4000	4	6000	2.0986
FR-IT	995	995	1000	1	1995	1.6956
GR-IT	500	2500	2500	3	3000	2.7917
HU-AT	500	2500	2500	3	3000	2.7917
HU-SK	600	3000	3000	3	3600	2.7917
NO-DK	1632	4896	5000	5	6632	2.4021
NO-NL	723	3615	3500	4	4223	2.7648
SE-DE	615	3075	3000	3	3615	2.7712
SI-IT	620	1860	2000	2	2620	2.4412

For Vision 5, TOC of €0.35164 billion is calculated by GAMS after implementing the suggested interconnections, and the BCI is 3.39.

Finally, the interconnections for the Vision 6 is presented in the table below, with a correspondent BCI of 2.33. For both scenarios the interest rate r used is 5% and the life-time of the transmission y connection is 30 years, giving a CRF value of 0.0650 (see Eq. 15).

Table 10 – Alternative 2 for Vision 6 Based on partially constrained values, ranked by highest ACC values

Alternative 2 - 2050	**Based on partially constrained values from 2030**					
Interconnection	TC1	TC	AC	n	TC2	IC
AT-IT	295	2360	2500	3	2795	3.2486
BG-MK	400	400	500	1	900	1.8109
BG-RS	450	900	1000	1	1450	2.1700
CH-DE	4000	2000	2000	4	6000	1.4054
CZ-DE	3650	1825	2000	4	5650	1.4369
DK-DE	2365	2365	2000	2	4365	1.6128
EE-FI	1016	3048	3000	3	4016	2.3744
ES-FR	1300	2600	2500	3	3800	2.0726
GR-IT	500	2500	2500	3	3000	2.7917
HU-SK	600	1800	1500	2	2100	2.2527
LV-EE	879	2637	2500	3	3379	2.3465
NO-DK	1632	1632	1500	2	3132	1.6518
NO-NL	723	3615	3500	4	4223	2.7648
RO-RS	550	550	500	1	1050	1.6466
SE-DE	615	2460	2500	3	3115	2.6223
SE-PL	600	2400	2500	3	3100	2.6422
SI-IT	620	2480	2500	3	3120	2.6158

Total investment costs for alternatives 1 and 2 for 2050 are €11.68 and €11.34 billion per year.

Table 11 and Figure 16 summarizes all interconnections suggested for 2030 and 2050 and their respective BCI value.

Table 11 – Summary of variable and investment costs, benefits and BCI index for the transmission interconnections alternatives for 2030 and 2050

Year	Alternative	TOC (in billions euros, 1 day)	IC (in billions euros, per year)	Benefits (in millions euros, 1 day)	BCI
2030	1	0.32145	6.684	0.1347601	0.8177
	2	0.32100	5.300	0.1954410	1.4940
	3	0.32161	4.362	0.1860698	1.7294
	4	0.32162	5.847	0.4414692	1.5303
	5	0.32045	4.953	0.1782042	1.4584
	6	0.32095	4.394	0.1745896	1.6104
2050	1	0.35164	11.68	0.9781289	3.3938
	2	0.32061	11.34	0.6525149	2.3334

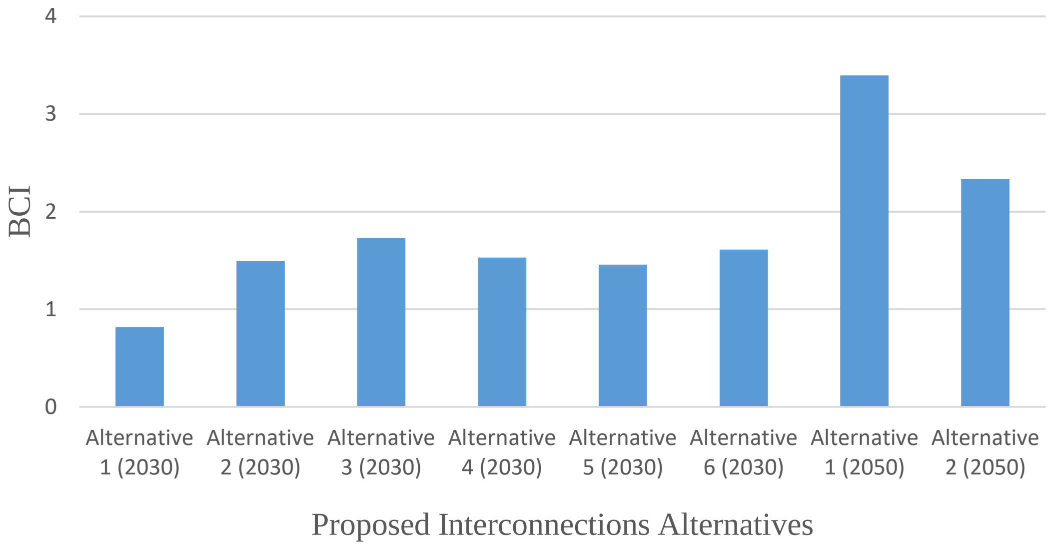

Figure 16 – Difference in the BCI for different transmission interconnections alternatives for 2030 and 2050

As it is showed in Table 11, the total operational system costs (TOC) calculated by GAMS are similar for all alternatives, except alternative 1 from 2050 presenting a value of 0.35164 billons euros. This is mainly related to the fact that electricity demand for this scenario (Vision 5) is the highest among all visions, and the CO_2 tax is at the highest value. Since generation is directly connected with the demand for electricity, the cost of operation increased as more power plants need to be dispatched. Investment Cost (IC) is annualized using the CRF expression, Eq. (14). In this case the highest values are the alternatives from 2050, since more transmission lines are proposed, both because of the increase of the electricity demand and the increase of

RES in the generation mix. More intermittent energy sources require more transmission reinforcement, both for importing and exporting. The benefits calculated for each alternative is the sum of the avoided congestion costs (ACC) of all connections proposed, for the peak day simulated. The value of ACC is directly related to the degree of congestion and the nodal price difference between the two countries. The highest benefit value comes from alternative 1 from 2050, representing that 0.978 millions of euros could be saved on the peak day, if the proposed line reinforcements were applied. A high benefit affects positively the BCI.

According to the graph in Figure 16, BCI for Alternative 1 is the only not to reach 1, thus not being profitable. 2050's alternatives shows a higher BCI of approximately, making them very profitable. This is due the high number of suggested interconnections for 2050's alternatives (16 and 17 interconnections, respectively) and their high NTC individual value.

5.2.4 LMP effect after investment in transmission

Now that suggested NTC values are calculated, the LMP effect can be studied for the different vision scenarios, for 2030 and 2050. Starting with Vision 1, Figure 17 shows that regional prices are somewhat similar when compared with base case scenario from 2015, with peak values from BE, GB and NL reaching €80/MWh. Vision 2 presents similar peak values for LMP but many countries presents a lower price when compared to Vision 1. This is due technological development effect on the load integration, which in the model is translated as a decrease of the load electricity demand.

For Visions 3 and 4, the comparison is also made between them as showed in Figure 18. Vision 3 shows a significant increase of electricity prices on fossil-fuel based countries due the high tax on CO_2 implemented. FR reaches €106/MWh and tops the highest LMP for Vision 3. This can be explained by the big amount of nuclear power that is replaced by wind (same cost) and gas power (higher cost). However LMP prices drop again in Vision 4 because, despite having high CO_2 taxes, the penetration of RES is very high combined with a strong load integration. Nevertheless peak prices exceed €80 and reach €88/MWh in BE and NE. High penetration of RES contributes for a high variation of LMP between countries. Congestion is significant higher thus requiring a higher need for investment in transmission capacity.

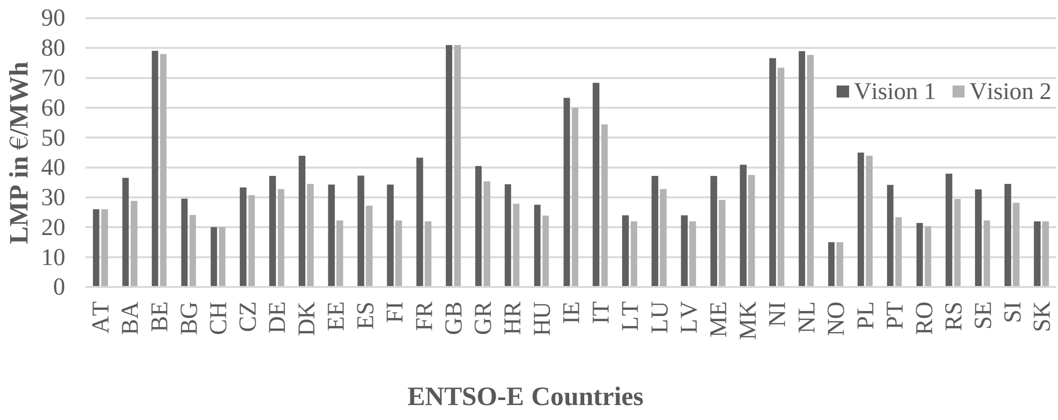

Figure 17 – LMP for 2030 scenarios, Visions 1 and 2

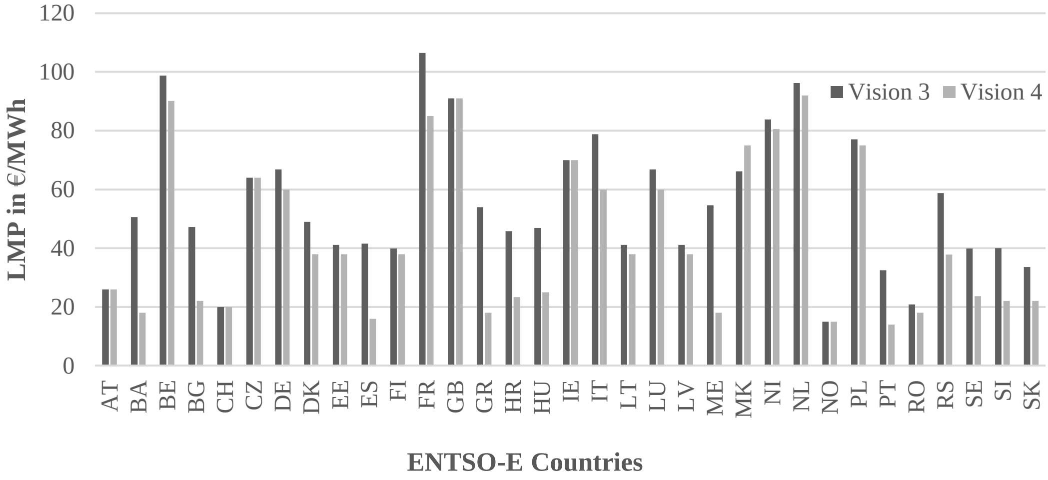

Figure 18 – LMP for 2030 scenarios, Visions 3 and 4

For Visions 5 and 6, 1-day interval is not a good representation of the nodal pricing because of the high share of RES. More data is necessary to create a reliable LMP curve, taking the monthly average of each vision scenario. Figures 17 and 18 show that countries still reliable on fossil-fuel, especially gas power, such as BE, NL, GB and IT are penalized in this model and represent the highest LMP among the ENTSO-E countries. Vision 6 presents the lowest LMP prices of all scenarios, due to a high penetration of RES combined with a lower electricity demand when compared with Vision 5. So, a high share of RES in the NGC will result in a downward effect on LMPs when the simulation takes a longer period into consideration, since their operational costs are lower than the conventional fossil-fuel technologies. It becomes even more apparent when a higher tax is imposed for CO_2 emissions. Differences in the load demand and load integration affect directly the LMP, since the demand curve is inelastic for changes in price of electricity. Investment in transmission contributes directly for reducing the congestion between countries, thus reducing congestion costs. It also contributes to increase the reliability of the high intermittent nature of wind and solar power to export when the natural source is abundant and important and it is scarce. A big geographical scope conciliates well with high penetration of RES and centralized power system operation, since wind and power resources varies according to the location and are commonly far away from the large load centres.

Looking at Figure 19 and 20, it is noticed that all countries have their LMP reduced, except DE, LU (both visions) and IT (Vision 5). Since there is a considerable increase of the electricity demand for the 2050 vision scenarios, the new RES generation has to fill the gap of the conventional ones.

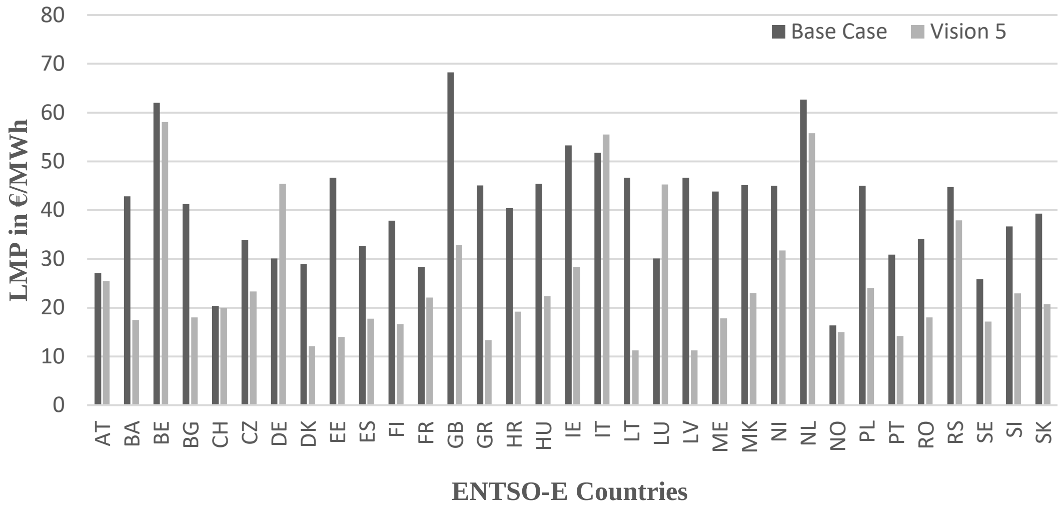

Figure 19 – 2050 LMP (in €/MWh), Vision 5

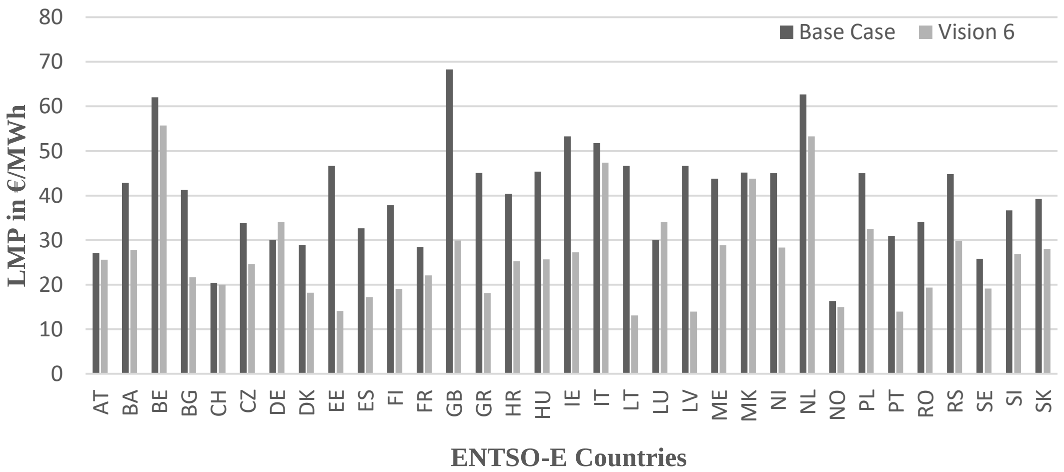

Figure 20 – 2050 LMP (in €/MWh), Vision 6

In the model this is translated to shifting up the load demand curve in a uniform way, which may not be true in reality due the technological use of DSM, smart grids or Distributed Generation, prioritizing reducing peak load or allowing increase of load on low load periods. Another factor is that the *CGen* of different technologies may vary between countries more than the way they vary in the model, for instance, by heavy subsidies from the government to support RES. CF can also vary more than the model meaning that is not only related to geographical position (northern and southern Europe) but also per type of technology being used. For example, in DE solar power is predominantly PVs while in ES the main used technology is CSP. The highest decrease of LMP is GB, explained by the substantial shift from coal power to wind power, the latter having lower *CGen*.

6 Conclusions and Future Work

6.1 Conclusions

After simulations and comparisons between the different study scenarios, some effects can be noticed. The economic conditions affect the price of generation. When the macro-economic situation is more favourable, running costs are lower, thus affecting LMP downwards. This is especially critical for RES technologies (wind and solar power) that are predicted to lower their cost significantly on the future horizon. RES technologies have lower running costs compared to conventional technologies (zero fuel costs), thus systems with higher share of RES tend to have lower electricity prices compared to fossil-fuel based systems. However, that phenomenon is not always present, since RES is highly intermittent and dependant on availability of the nature resources, and also because some conventional existing power plants (i.e. hydro and nuclear power) are already cheap to run in the base case scenario (2015).

Regarding the two objectives defined in Chapter 1, the main findings can be listed below:

1. With regard to objective 1, it can be concluded that CBA analysis is helpful to identify critical paths (most congested power lines) and rank the best investment alternatives between the ENTSO-E member countries, both in terms of extra net transfer capacity and quantity of interconnections. New interconnection expansion capacity leads to a decrease of the LMP. Interconnections reinforcements AT-IT, CH-DE, NO-NL are presented in most of the suggested alternatives, representing critical paths with rather different LMP and great potential for capacity expansion. Transmission reinforcement alternatives for 2050 presents the best BCI and only alternative 1 from 2030 is calculated as not profitable.
2. From objective 2, it can be concluded that a market-model minimizing total system operational costs is powerful to help decision maker to choose the best long-term investment plan in transmission capacity. Yearly total system investment costs for transmission suggested varies from €4 to €11 billion dollars, for 2030 and 2050 scenarios respectfully. Low cost of generation from RES tend to reflect a lower electricity price for most cases, but price can also increase (i.e. DE and FR replacing conventional nuclear power with RES). The results are strongly affected by European economic conditions, energy policies and society behaviour regarding load demand. Comparing the total investment values from proposed transmission alternatives of 2030 (€4.89 billion) and 2050 (€11.68 and €11.34 billion each alternative) with the TYNDP report from 2014 where the total investment costs of all projects amounts €150bi, it can be concluded that only a small fraction of investment alternatives are presented in this thesis when 2030 is the target year scenario, but when the year 2050 is considered, the total value of investment in transmission is similar. It is also related to all indirect and external costs due policies, environmental and societal costs which were not included in the power market model.

6.2 Future Work

For future work, the topics below are important for the complementarity of the thesis. They include:

- Detailed modelling of RES power curves availability (solar and wind power), based on historical data and probability models, making the model closer to reality.
- Modelling and analyses of the effects of storage on the market-model, for example hydropower pump storage, batteries and EVs.
- How smart-grids, distributed generation and demand side management affect the load and the power supply, so the producer and consumer can adapt their behaviour in a more economical way.
- Add Iceland (IS), Cyprus (CY) and non-ENTSO-E member countries such as Russia and North Africa countries as new included nodes.
- Allow new transmission connections within countries.

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http://www.energynautics.com/downloads/europeangridstudy2030-2050/energynautics_EUROPEAN-GRID-STUDY-2030-2050.pdf

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APPENDIX

APPENDIX A

41 TSOs from 34 countries are members of ENTSO-E (the European Network of Transmission System Operators for Electricity).

Country	Companies (TSOs)	Abbreviation
AT **Austria**	Austrian Power Grid AG Vorarlberger Übertragungsnetz GmbH	APG VUEN
BA **Bosnia and Herzegovina**	Nezavisni operator sustava u Bosni i Hercegovini	NOS BiH
BE **Belgium**	Elia System Operator SA	Elia
BG **Bulgaria**	Electroenergien Sistemen Operator EAD	ESO
CH **Switzerland**	Swissgrid ag	Swissgrid
CY **Cyprus**	Cyprus Transmission System Operator	Cyprus TSO
CZ **Czech Republic**	ČEPS a.s.	ČEPS
DE **Germany**	TransnetBW GmbH TenneT TSO GmbH Amprion GmbH 50Hertz Transmission GmbH	TransnetBW TenneT DE Amprion 50Hertz
DK **Denmark**	Energinet.dk	Energinet.dk
EE **Estonia**	Elering AS	Elering AS
ES **Spain**	Red Eléctrica de España S.A.	REE
FI **Finland**	Fingrid Oyj	Fingrid

FR **France**	Réseau de Transport d'Electricité	RTE
GB **United Kingdom**	National Grid Electricity Transmission plc System Operator for Northern Ireland Ltd Scottish Hydro Electric Transmission plc Scottish Power Transmission plc	National Grid SONI SHE Transmission
GR **Greece**	Independent Power Transmission Operator S.A.	IPTO
HR **Croatia**	HOPS d.o.o.	HOPS
HU **Hungary**	MAVIR Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság	MAVIR ZRt.
IE **Ireland**	EirGrid plc	EirGrid
IS **Iceland**	Landsnet hf	Landsnet
IT **Italy**	Terna - Rete Elettrica Nazionale SpA	Terna
LT **Lithuania**	Litgrid AB	Litgrid
LU **Luxembourg**	Creos Luxembourg S.A.	Creos Luxembourg
LV **Latvia**	AS Augstsprieguma tĪkls	Augstsprieguma tĪkls
ME **Montenegro**	Crnogorski elektroprenosni sistem AD	Crnogorski elektroprenosni sistem
MK **FYR of Macedonia**	Macedonian Transmission System Operator AD	MEPSO
NL **Netherlands**	TenneT TSO B.V.	TenneT NL
NO **Norway**	Statnett SF	Statnett

PL **Poland**	Polskie Sieci Elektroenergetyczne S.A.	PSE S.A.
PT **Portugal**	Rede Eléctrica Nacional, S.A.	REN
RO **Romania**	C.N. Transelectrica S.A.	Transelectrica
RS **Serbia**	JP Elektromreža Srbije	EMS
SE **Sweden**	Svenska Kraftnät	SVENSKA KRAFTNÄT
SI **Slovenia**	ELES, d.o.o.	ELES
SK **Slovak Republic**	Slovenská elektrizačná prenosová sústava, a.s.	SEPS

Source: https://www.entsoe.eu/about-entso-e/inside-entso-e/member-companies/Pages/default.aspx

Appendix B

NTC Matrix – Base Case Scenario 2015

NTC (MW)	ENTSOe																															
From \ To	AT	BA	BE	BG	CH	CZ	DE	DK	EE	ES	FI	FR	GB	GR	HR	HU	IE	IT	LT	LU	LV	ME	MK	NI	NL	NO	PL	PT	RO	RS	SE	SI	SK
ENTSOe AT					800	800	2000									800		295														950	
BA															750							400								500			
BE												2300													2400								
BG														600									400						600	450			
CH	1200						4000					1100						4165															
CZ	1000						3650																				600						2200
DE	2200				1500	1000		2100				3200								980					3850		1200				615		
DK							2365																			1632					2440		
EE											1016										1000												
ES												1000																1710					
FI									1000																						2300		
FR			3400		3200		2700			1300			2000					2575															
GB												2000					530							1000									
GR				500														500					400										
HR		700														1000														500		1500	
HU	500														1200														700	600			600
IE													530											1000									
IT	285				1810							995		500																		660	
LT																					684												
LU							980																										
LV									879										1234														
ME		400																												650			
MK				200										300																400			
NI													1000				1000																
NL			2400				3000																			723							
NO								1632																	723						3695		
PL						1800	1100																								600		600
PT										3060																							
RO				200												700														700			
RS		600		200											600	800						700	700						550				
SE							615				2700															3995	600						
SI	950														1500			620															
SK						1200										800											500						

2014: http://www.nordpoolspot.com/globalassets/download-center/tso/max-ntc.pdf

2011: https://www.entsoe.eu/fileadmin/user_upload/_library/ntc/archive/NTC-Values-Winter-2010-2011.pdf

2015: ENTSO-E Transparency Portal https://transparency.entsoe.eu/transmission-domain

Appendix C

Capacity Factor for Solar Power using FLH method.

The Figure C1 below shows the solar irradiation map of Europe.

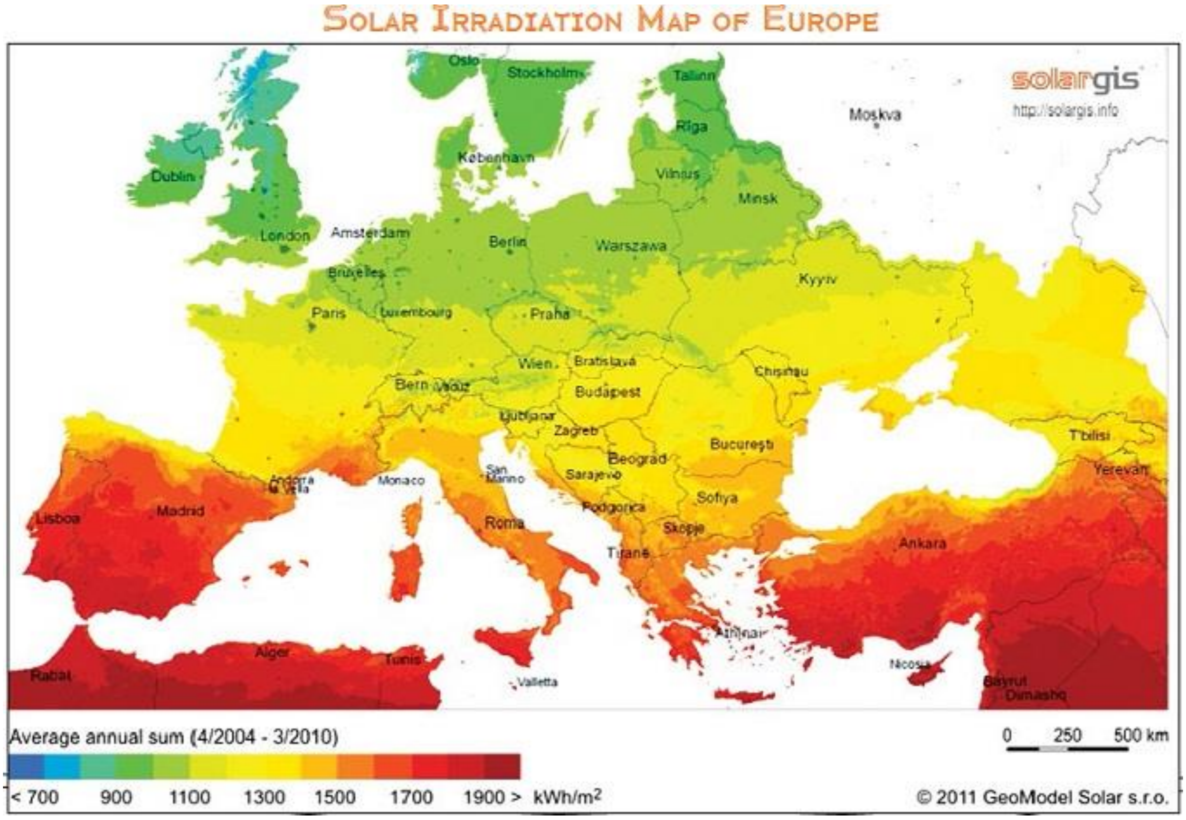

Figure C1 – Solar irradiation map of Europe in kWh/m^2 (yearly average). Source: http://solargis.info

The Figure C2 shows the FLH associated with the countries in Europe as a yearly average.

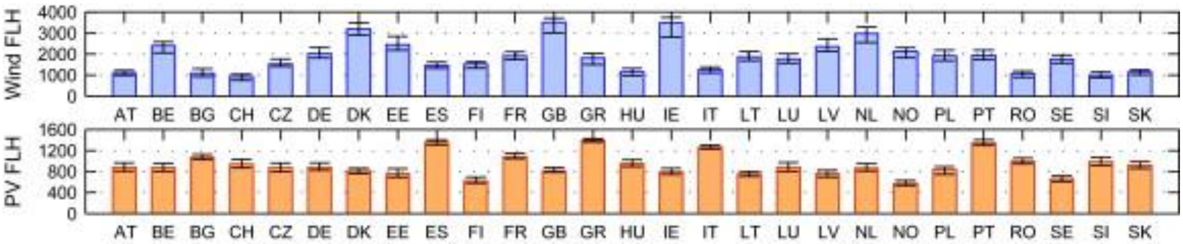

Figure C2 – Equivalent FLH for Wind and Solar power for Europe countries (yearly average). Source: http://www.sciencedirect.com/science/article/pii/S0360544214002680

Appendix D – Net Generating Capacity (NGC) Tables

Table D1-A – Net Generating Capacity in MW by type of technology. Base Case Scenario – 2015. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	13427	0	2140	715	254	385	4901	1173
BA	2060	0	0	0	0	0	0	1578
BE	1425	5926	1835	2953	709	188	6143	470
BG	3191	2000	358	275	20	0	19	5648
[a]CH	13805	3375	60	756	275	0	501	0
[b]CZ	2261	4040	278	2061	0	0	1205	10849
[c]DE	10662	10952	39937	38994	6609	3745	26694	50685
[d]DK	9	0	4897	606	916	1051	2314	4791
EE	8	0	328	0	80	1698	181	0
ES	19396	7572	22740	6535	671	650	30429	10609
FI	3264	2752	496	0	2051	1705	1611	4252
FR	25411	63130	357	39	0	6670	6121	4810
GB	3969	9779	8399	0	1137	566	30287	16714
GR	3237	0	1613	2429	0	718	4913	4459
HR	2112	0	340	34	8	590	590	590
HU	57	1887	329	6	134	410	4224	1099
IE	1510	0	1907	0	0	811	3801	855
[e]IT	22009	0	8683	18609	3576	2209	47786	18032
LT	1026	0	282	68	29	160	2651	680
[f]LU	1334	0	57	109	11	0	495	0
LV	1578	0	51	0	82	0	1136	0
ME	660	0	0	0	0	0	0	210
MK	539	0	35	0	0	0	0	1076
NI	12	0	1447	0	43	0	0	5904
NL	38	492	2874	1000	400	0	19590	7270
NO	31062	0	856	0	0	0	1609	0
PL	2354	0	3758	14	375	345	984	27793
PT	5684	0	4486	221	582	0	4719	1756
RO	6332	1298	2896	1101	92	0	4861	5872
RS	2990	0	0	0	0	0	0	5566
SE	16155	9528	3500	79	3082	0	5285	0
SI	1245	696	3	262	16	0	490	1228
SK	2536	1940	3	531	254	0	1346	1346
Total	201358	125367	114945	77397	21406	21901	214886	195315

Extra sources, complementing information from specific TSOs for some countries:

[a] CH for Oil and Gas power share in the generation mix. Available: https://www.iea.org/publications/freepublications/publication/OilGasSecuritySwitzerland2012.pdf

[b] CZ share of renewables and conventional power. Available: https://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_czechrepublic.pdf

[c] DE gross power production by source to differentiate fossil-fuel proportions. Available: https://www.cleanenergywire.org/factsheets/germanys-energy-consumption-and-power-mix-charts

[d] DK share of electricity generation by installed capacity. Available: https://www.energinet.dk/EN/KLIMA-OG-MILJOE/Miljoerapportering/Elproduktion-i-Danmark/Sider/Termiske-vaerker.aspx

[e] IT share of annual electricity production, report from 2013. Available: http://download.terna.it/terna/0000/0064/27.PDF

[f] LU gross electricity generation mix between 2008 and 2011, fossil-fuel considered is Gas. Available: https://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_luxembourg.pdf

Table D1-B – Generation operational costs (CGen) in €/MWhe for the different power plant types in 2015. Data and assumptions based on "IEA: Projected Costs of Generating Electricity 2015 Edition".

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	26	22	28	6	39	106	82	45
BA	18	22	20	24	40	106	82	45
BE	18	22	20	22	40	106	78	34
BG	18	22	20	19	40	106	82	45
CH	20	26	30	30	40	106	72	45
CZ	7	24	22	20	40	106	70	34
DE	20	22	34	19	40	106	82	30
DK	18	22	14	2	38	106	83	45
EE	18	22	20	15	40	80*	82	45
ES	16	22	28	45	60	106	82	45
FI	18	20	20	24	38	106	82	30
FR	18	22	22	38	40	106	75	45
GB	41	31	36	37	40	106	81	45
GR	18	22	20	24	40	106	82	45
HR	18	22	20	24	40	106	82	45
HU	18	20	32	38	40	106	78	45
IE	18	22	36	24	40	106	60	45
IT	35	22	21	49	60	106	80	45
LT	18	22	14	24	40	106	82	45
LU	18	22	20	24	40	106	82	45
LV	18	22	20	24	40	106	82	45
ME	18	22	20	24	40	106	82	45
MK	18	22	20	24	40	106	82	45
NI	18	22	36	37	40	106	82	45
NL	18	22	20	24	40	106	82	39
NO	15	22	20	24	38	106	82	45
PL	18	22	20	24	40	106	72	45
PT	14	22	18	18	40	106	80	39
RO	18	22	20	24	40	106	82	45
RS	18	22	20	24	40	106	82	45
SE	15	22	20	24	38	106	82	45
SI	18	22	20	24	40	106	82	45
SK	18	22	20	24	40	106	82	68
Average	19	22	23	25	41	105	80	44

*EE uses shale oil power instead of conventional oil

Table D2 – Net Generating Capacity in MW by type of technology – Vision 2. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	16418	0	3880	2000	800	196	3915	598
BA	2107	0	350	0	0	0	0	2158
BE	1438	0	4900	4050	1700	0	7370	0
BG	3150	2000	900	1250	0	0	760	4710
CH	18510	2115	120	1750	600	0	0	0
CZ	2170	4140	580	2560	1110	0	915	5640
DE	13257	0	61200	46860	6960	1026	15463	35975
DK	9	0	8410	840	1720	735	2604	410
EE	10	0	400	0	886	413	94	0
ES	23450	7120	27650	33150	2400	0	21572	5900
FI	3400	5550	2500	100	4340	1360	0	2265
FR	25200	57644	13900	8500	1400	819	6051	1740
GB	4754	4552	57300	7460	5450	109	36736	2897
GR	4259	0	4880	4050	480	0	3111	2876
HR	2700	0	700	100	300	200	1200	1200
HU	56	4108	750	60	760	407	2980	470
IE	508	0	3600	10	250	260	3575	750
IT	22635	0	13400	27140	7240	1394	34886	7926
LT	1265	1303	500	70	310	0	740	680
LU	1344	0	90	120	70	0	375	0
LV	1621	0	360	60	250	0	1036	0
ME	1215	0	120	0	0	0	0	450
MK	716	0	100	30	30	0	440	410
NI	0	0	1220	150	110	200	1142	0
NL	38	486	6160	5100	300	0	7776	4610
NO	38900	0	2080	0	0	0	425	0
PL	2426	3000	6450	500	7077	0	2804	12523
PT	7858	0	5300	2010	720	0	3693	0
RO	7737	2630	4200	2000	500	0	3331	4800
RS	4308	0	530	20	0	0	296	4965
SE	16203	7992	7840	0	5340	0	0	0
SI	1929	696	40	280	105	0	505	545
SK	3140	4004	60	550	514	0	256	223
Total	232731	107340	240470	150770	51722	7119	164051	104721

Table D3 – Net Generating Capacity in MW by type of technology – Vision 3. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	18471	0	5500	3500	1200	196	6030	0
BA	2317	0	900	100	0	0	373	2158
BE	2730	0	8500	5800	2500	0	6840	0
BG	3468	2000	1700	2300	0	0	1500	4010
CH	20160	1145	370	4250	1120	0	0	0
CZ	2170	1880	880	3690	1110	0	1990	5640
DE	17637	0	100750	60740	9340	871	34429	25149
DK	9	0	10750	1970	1720	735	3746	410
EE	20	0	400	100	956	0	94	0
ES	25050	7120	39300	25000	5100	0	29208	4160
FI	4350	3350	5000	2500	5250	2165	970	1460
FR	27200	37646	36600	24100	4800	819	14051	1740
GB	7682	9022	51090	15560	8420	75	36616	0
GR	4699	0	7800	5300	650	0	6252	2212
HR	3000	0	1500	200	300	200	1700	1200
HU	100	3000	1000	200	1250	407	4977	0
IE	558	0	5500	500	1200	260	4270	0
IT	23535	0	18990	40400	10750	1386	37993	7056
LT	1265	0	650	80	330	0	923	680
LU	1344	0	130	200	100	0	375	0
LV	1621	0	1000	20	400	0	1036	0
ME	1271	0	0	20	0	0	0	450
MK	716	0	150	40	30	0	720	740
NI	50	0	1730	300	320	150	1590	0
NL	38	486	12700	15400	5080	0	9358	0
NO	40800	0	2910	0	0	0	855	0
PL	3176	0	11000	4000	6450	0	1911	11960
PT	9717	0	6400	910	850	0	3717	0
RO	8087	2630	5500	2800	800	0	4757	4800
RS	4308	0	1000	50	0	0	593	5659
SE	16203	7142	11400	1000	5340	660	950	0
SI	2005	1796	30	310	115	0	425	545
SK	3266	2880	90	720	724	0	843	223

Table D4 – Net Generating Capacity in MW by type of technology – Vision 4. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	22244	0	4750	3000	1200	196	6030	0
BA	2618	0	770	100	0	0	373	943
BE	2226	0	7518	4925	2500	0	6840	0
BG	3468	2000	1450	2598	0	0	1500	710
CH	20160	1145	295	3692	1120	0	0	0
CZ	2170	1880	880	3690	1110	0	1990	4734
DE	14505	0	96967	58990	9340	871	34429	23966
DK	9	0	12825	1405	1720	735	3746	410
EE	20	0	525	50	956	0	94	0
ES	25635	7120	40604	54130	5100	0	29208	4160
FI	3400	3350	4057	1300	5250	2165	970	0
FR	27200	37646	44851	18200	4800	819	14051	1740
GB	5470	9022	57901	11915	8420	75	36616	0
GR	4366	0	12335	8384	650	0	6252	1070
HR	3200	0	1400	929	300	200	1700	1200
HU	100	3000	7114	339	1250	407	4977	0
IE	558	0	5090	350	1200	260	4270	0
IT	23535	0	23459	42169	10750	1386	37993	5667
LT	1265	0	750	80	330	0	923	0
LU	1344	0	155	175	100	0	375	0
LV	1621	0	900	15	400	0	1036	0
ME	1271	0	155	20	0	0	0	450
MK	716	0	175	736	30	0	720	330
NI	0	0	1590	250	320	150	1590	0
NL	38	486	9995	9700	5080	0	9358	0
NO	48700	0	2495	0	0	0	855	0
PL	3176	0	9950	2750	6450	0	1911	11960
PT	9717	0	8572	3280	850	0	3717	0
RO	8100	2630	9371	2650	800	0	4757	1251
RS	4308	0	765	512	0	0	593	1609
SE	16203	7142	9620	500	5340	660	950	0
SI	2005	1796	931	444	115	0	425	545
SK	3266	2880	831	665	724	0	843	0
Total	262614	80097	379046	237943	76205	7924	219092	60745

Table D5 – Net Generating Capacity in MW by type of technology – Vision 5. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	22021	0	6875	7226	1250	0	5250	0
BA	4919	0	2599	921	250	0	0	0
BE	2640	0	12901	8421	3500	0	18500	0
BG	11752	1600	4403	3296	1750	0	1500	800
CH	17696	0	1382	10500	1250	0	3500	0
CZ	2763	11200	10279	3925	500	0	3000	800
DE	14899	0	118677	54428	9000	0	41000	4000
DK	13	0	49723	2606	3000	0	2250	0
EE	738	0	8244	409	250	0	1000	0
ES	37683	8000	67448	89822	6000	0	31000	800
FI	7475	3200	37198	1505	3000	0	3000	0
FR	39703	72000	84219	72090	6750	0	16500	800
GB	11805	25600	118577	6350	4500	0	30250	800
GR	9633	0	25861	8266	1500	0	1000	0
HR	5062	0	6255	882	250	0	1000	0
HU	1512	6400	4889	3127	2500	0	2000	0
IE	1811	0	15479	258	500	0	6250	0
IT	24503	0	41293	69252	5500	0	39500	2400
LT	1938	1600	14959	529	750	0	2500	0
LU	1525	0	617	121	250	0	1000	0
LV	1631	0	13709	425	750	0	1000	0
ME	3988	0	520	616	0	0	0	0
MK	1776	0	371	443	0	0	500	0
NI	0	0	5165	37	0	0	2500	0
NL	104	1600	23916	6173	3000	0	22500	800
NO	80519	0	13718	480	250	0	500	0
PL	5237	9600	62521	3807	4750	0	5000	800
PT	11237	0	11474	5544	1000	0	4750	0
RO	13693	4800	4818	5404	3250	0	3500	800
RS	4351	0	1429	1235	250	0	2000	800
SE	26608	6400	36358	1624	3000	0	500	0
SI	2055	2000	472	1739	250	0	500	0
SK	1288	3200	4697	1004	1000	0	1000	0
Total	372575	157200	811048	372465	69750	0	254250	13600

Table D6 – Net Generating Capacity in MW by type of technology – Vision 6. Data provided by ENTSO-E.

Country	Hydro	Nuclear	Wind	Solar	Biomass	Oil	Gas	Coal
AT	16433	0	5751	7040	1250	0	3500	0
BA	1621	0	767	1775	0	0	500	800
BE	1630	0	8899	5182	2500	0	21250	0
BG	4428	1600	1811	3723	750	0	2250	800
CH	16849	0	1382	9825	1500	0	5250	0
CZ	2049	8000	6155	4072	1000	0	500	0
DE	12261	0	88844	51753	9000	0	48500	13600
DK	4	0	29951	1591	3000	0	500	0
EE	510	0	5412	538	250	0	500	0
ES	23478	8000	44351	85798	5000	0	29250	800
FI	5799	3200	10859	569	3000	0	5750	2400
FR	31422	48000	57780	68366	7750	0	16250	800
GB	7406	20800	96385	9337	4250	0	12500	1600
GR	3502	0	15565	10352	1000	0	3000	0
HR	3091	0	1822	1299	0	0	1750	800
HU	636	3200	3481	3787	1250	0	4000	0
IE	1377	0	12303	558	250	0	1750	0
IT	19408	0	22348	72729	8000	0	46750	5600
LT	1386	1600	7474	902	500	0	3250	0
LU	1192	0	280	171	0	0	1000	0
LV	1460	0	6848	699	500	0	1750	0
ME	698	0	106	458	0	0	500	0
MK	415	0	196	617	0	0	1000	800
NI	0	0	5720	72	0	0	750	0
NL	18	0	19198	5362	2750	0	26750	3200
NO	52360	0	6755	1303	750	0	0	0
PL	2939	8000	27180	5386	2750	0	3750	2400
PT	7154	0	8179	7555	1000	0	6000	0
RO	6074	3200	4000	6159	1500	0	5750	1600
RS	2827	0	757	1819	250	0	1500	2400
SE	18455	8000	9640	1527	2750	0	1000	0
SI	1126	1000	382	1651	250	0	500	0
SK	906	1600	1232	1308	500	0	1750	0
Total	248915	116200	511811	373283	63250	0	259000	37600

Appendix E – GAMS Code

```
*---------------------------------------------------------------------
* IMPLEMENTATION OF EUROPEAN ELECTRICITY MARKET MODELLING
* Calculates unit dispatch and total system costs for the system
*---------------------------------------------------------------------
option work =500000000;
option solprint = ON;
option sysout = ON;
option ITERLIM = 100000000;
option RESLIM = 8640000;
option lp=xa;
*ENTSOe - 33 buses excluding Cyprus and Iceland
*Low Resolution, 1 node per country network
Set
         i buses /
AT, BA, BE, BG, CH, CZ, DE, DK, EE, ES, FI, FR,
GB, GR, HR, HU, IE, IT, LT, LU, LV, ME, MK, NI,
NL, NO, PL, PT, RO, RS, SE, SI, SK /
;
Alias(i,j);
*timesteps (one hour resolution)
Sets
        t_wind wind profile /1*8760 all hours of the year/
*       t(t_wind) subset hours winter /1*24 first 24h jan/
*       t(t_wind) subset hours winter_work /503*526 3rd wed jan/
*       t(t_wind) subset hours jan    /1*744 january/
*       t(t_wind) subset hours jul    /4345*5088 july/
*       t(t_wind) subset hours summer /4345*4368 first 24h jul/
*       t(t_wind) subset hours summer_weekend /4465*4488 1st sun jul/
*       t(t_wind) subset all hours /1*8760 all hours of the year/
;
*Set Slack bus in Germany
Set
         slack(i) Slack bus /DE/;
         Scalar Base system base MVA  /100/;
Sets
*Power plants technologies sets
         plant   power plant aggregates
         / Hydro hydro power
         Nuclear nuclear power
```

```
          Wind    wind power
          Solar   solar power
          Biomass biomass power
          Oil     oil power
          Gas     gas power
          Coal    coal power /
*Line data sets
    LineD   Line data table headings /X, length, MaxFlow/
*Demand set
    Demand  Demand /DemENTSOe/
;
*DATA INPUT
*GENERATION DATA
*NGC - Net Generating Capacity
Parameter GenPmaxENTSOe(i,plant)  Maximum Capacity for each plant
type at bus i in MW
$CALL GDXXRW.EXE InputDataEU_NGC.xlsx par=GenPmaxENTSOe
rng=GenData!B131:J164 O=GPmaxENTSOeData.gdx
$GDXIN GPmaxENTSOeData.gdx
$LOAD GenPmaxENTSOe
$GDXIN
;
*Convert generation data in per unit
Parameter Pmax(i,plant) Maximum capacity for each plant type in pu.;
Pmax(i,plant)=(GenPmaxENTSOe(i,plant))/Base;
Display Pmax;
*Variable Cost Data in €/MWh
Parameter CGen(i,plant)  Variable Costs for each plant type at bus i
in USD per MW
$CALL GDXXRW.EXE InputDataEU_NGC.xlsx par=CGen rng=GenData!B167:J200
O=CGenData.gdx
$GDXIN CGenData.gdx
$LOAD CGen
$GDXIN
;
Display CGen;
*SOLAR Full Load Hours method by country
Parameter FLHs(i) Full Load Hours solar power would generate at full
capacity to produce the yearly energy [in hours];
FLHs('AT')   =     800;
FLHs('BA')   =     1000;
FLHs('BE')   =     800;
```

```
FLHs('BG')   =    1000;
FLHs('CH')   =    900;
FLHs('CZ')   =    850;
FLHs('DE')   =    900;
FLHs('DK')   =    850;
FLHs('EE')   =    800;
FLHs('ES')   =    1400;
FLHs('FI')   =    500;
FLHs('FR')   =    1100;
FLHs('GB')   =    800;
FLHs('GR')   =    1500;
FLHs('HR')   =    950;
FLHs('HU')   =    950;
FLHs('IE')   =    800;
FLHs('IT')   =    1200;
FLHs('LT')   =    750;
FLHs('LU')   =    850;
FLHs('LV')   =    700;
FLHs('ME')   =    1100;
FLHs('MK')   =    1200;
FLHs('NI')   =    700;
FLHs('NL')   =    800;
FLHs('NO')   =    500;
FLHs('PL')   =    800;
FLHs('PT')   =    1400;
FLHs('RO')   =    1000;
FLHs('RS')   =    1000;
FLHs('SE')   =    600;
FLHs('SI')   =    1100;
FLHs('SK')   =    1100;
Parameter CFsolar(i) Capacity factor for solar power;
CFsolar(i) = FLHs(i)/8760;
Parameter CFhydro Capacity factor for hydro power for all power
plants;
CFhydro = 0.8;
*WIND
Parameter
*Input data to read from files
       p_wind(t_wind)               normalized wind production
profile [share of installed capacity]
;
```

```
*Read wind profile from file 'wind.inc'
Parameter p_wind(t_wind) /
$include ./wind.inc
/;
*DEMAND DATA
*LOAD ENTSO-E jan,apr,jul,oct
Parameter DemENTSOe(i,t) Demand for 2014 (ENTSOe) in MW
$CALL GDXXRW.EXE InputDataEU_NGC.xlsx par=DemENTSOe
rng=LoadData!A1:JTQ34 O=DemENTSOeData.gdx
$GDXIN DemENTSOeData.gdx
$LOAD DemENTSOe
$GDXIN
;
Display DemENTSOe;
*Demand converted to pu
Parameter PD(i,t) demand at each bus in pu;
PD(i,t) = DemENTSOe(i,t)/Base;
Display PD;

*LINE DATA
*NTC MATRIX
Parameter LineMax(i,j) Line Flow limit in MW
$CALL GDXXRW.EXE InputDataEU_NGC.xlsx par=LineMax
rng=LineData!BF3:CM36 O=LineMaxData.gdx
$GDXIN LineMaxData.gdx
$LOAD LineMax
$GDXIN
;
Parameter LineSus(i,j) Reactance X of interconnections in Ohm
$CALL GDXXRW.EXE InputDataEU_NGC.xlsx par=LineSus
rng=LineData!B3:AI36 O=LineSusData.gdx
$GDXIN LineSusData.gdx
$LOAD LineSus
$GDXIN
;
Display LineMax, LineSus;
*Matrix for BB and Flowlim
*LineData(j,i,LineD)$(linedata(i,j,LineD) ne 0) =
LineData(i,j,LineD);
*Convert flow limit in per unit
Parameter Flowlim(i,j) Maximum power flow over line ij in pu.;
Flowlim(i,j)= LineMax(i,j)/Base;
```

```
Display Flowlim;
*Calculate susceptance B between buses i and j and to bus ii
Parameter BB(i,j)  susceptance BB over line;
BB(i,j)$(LineSus(i,j) ne 0) = -1/LineSus(i,j);
BB(i,j)$(LineSus(i,j) eq 0) = 0 ;
BB(i,i) = -sum(j,BB(i,j));
Display BB;
*DEFINITION OF VARIABLES AND EQUATIONS
VARIABLES
Cost             Total system cost in USD
Flow(i,j,t)      Active power flow between buses i and j
Delta(i,t)       Voltage angle at bus i in radians
;
Positive variables
P(i,plant,t)     Active power generation at bus i in per unit
;
*----------------------------------------------------------------------
EQUATIONS
TCost                   total system costs in €
Nodalbal(i,t)           active power balance on node i in pu
Powerflow(i,j,t)        active power flow between buses i and j in pu
Flowlimitup(i,j,t)      power flow limit between buses i and j in pu
Flowlimitlo(i,j,t)      power flow limit between buses i and j in pu
PLimUp(i,plant,t)       upper generation limit
DeltaLimLo(i,j,t)       Voltage angle Limitation due to DC-OPF
simplification
DeltaLimUp(i,j,t)       Voltage angle Limitation due to DC-OPF
simplification
Hydro1(i,t)             Limitation full load hours for Hydro
Solar1(i,t)             Limitation full load hours for Solar
Wind1(i,t)              Wind output limited by Wind Profile
;
*Objective function to be minimized
TCost..
         Cost =e= sum((i,plant,t), CGen(i,plant)*P(i,plant,t)*Base);
*CONSTRAINTS
*Active power balance each node must fulfill demand at each node i
for every time t
Nodalbal(i,t)..
         sum((plant), P(i,plant,t)) - sum((j) ,BB(i,j)*Delta(j,t))
=e= PD(i,t);
*Power flow equation, active power between two nodes
```

```
Powerflow(i,j,t)..
         Flow(i,j,t) =e= -(Delta(i,t)-Delta(j,t))*BB(i,j);
*Power plants do not produce more than maximum capacity at every node
i at every time t
PLimUp(i,plant,t)..
         P(i,plant,t) =L= Pmax(i,plant);
*Technical constraint of hydro using capacity factor
Hydro1(i,t)..
         P(i,"Hydro",t) =L= CFhydro*Pmax(i,"Hydro");
*Technical constraint of solar using time of utilization method for
FLH(i)
Solar1(i,t)..
         P(i,"Solar",t) =L= CFsolar(i)*Pmax(i,"Solar");
*Technical Constraint of Wind output limited by Wind Profile
Wind1(i,t)..
         P(i,"Wind",t) =L= p_wind(t)*Pmax(i,"Wind");
*Line power flow constraints
Flowlimitup(i,j,t)..
         Flow(i,j,t) =L= Flowlim(i,j);
Flowlimitlo(i,j,t)..
         Flow(i,j,t) =G= -Flowlim(i,j);
*Angle Limits
DeltaLimLo(i,j,t)$(BB(i,j) ne 0)..    Delta(i,t)-Delta(j,t) =G= -
1.57;
DeltaLimUp(i,j,t)$(BB(i,j) ne 0)..    Delta(i,t)-Delta(j,t) =L= 1.57;


MODEL PowerEU
/TCost,
Nodalbal,
Powerflow,
Flowlimitup,
Flowlimitlo,
PLimUp,
DeltaLimLo,
DeltaLimUp,
*Nuclear1,
Hydro1,
*Bio1,
Solar1,
Wind1,
/
```

```
;
SOLVE PowerEU using LP Minimizing Cost;
*Show & export final results
*total generation and demand per hour (and plant type)
Parameter TotGPlant(t,plant), TotG, TotD;
Loop(plant, TotGPlant(t,plant)= Base*sum(i, P.l(i,plant,t)) );
TotG(t)= Base* sum((plant,i), P.l(i,plant,t) );
TotD(t)= Base* sum(i, PD(i,t));
Parameter LineUsage(i,j,t) Percentage of Line Capacity between bus i
and j that is utilized in hour t;
LineUsage(i,j,t)$(Flowlim(i,j) >0)= Flow.l(i,j,t) / Flowlim(i,j);
*calculate LMP for each hour in €/MWh
Parameter LMP(i,t) marginal price for electricity per bus in € per
MWh;
LMP(i,t) = Nodalbal.m(i,t)/Base;
*Avoided Congestion Costs (ACC) in €
Parameter ACC(i,j,t) congestion costs that could be avoided by the
use of new transmission lines for each transmission ij;
ACC(i,j,t) = ((LMP(i,t)-LMP(j,t))*Flow.l(i,j,t))*Base;
Display Cost.l;
Display P.l;
Display Flow.l;
Display ACC;
Display LMP;
Display TotG, TotD, TotGPlant;
Display LineUsage;
*Output parameter to GDX file
execute_unload "resultsEU_NGC.gdx"
Cost.l
P.l
ACC
LMP
Flow.l
TotG
TotD
TotGPlant
Flowlim
LineUsage
*Write into Excel file
execute 'GDXXRW.exe resultsEU_NGC.gdx var=Cost.l rng=Cost!'
execute 'GDXXRW.exe resultsEU_NGC.gdx var=P.l rng=PGen!'
```

```
execute 'GDXXRW.exe resultsEU_NGC.gdx par=LMP rng=LMP!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=ACC rng=ACC!'
execute 'GDXXRW.exe resultsEU_NGC.gdx var=Flow.l rng=Flow!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=TotGPlant rng=TotGPlant!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=TotG rng=TotG!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=TotD rng=TotD!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=TotGPlant rng=TotGPlant!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=Flowlim rng=Flowlim!'
execute 'GDXXRW.exe resultsEU_NGC.gdx par=LineUsage rng=LineUsage!'
```