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National strategic investments in electricity transmission capacity in Europe

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Oppstartsdato **15. jan 2014**	Innleveringsfrist **11. jun 2014**
Oppgavens (foreløpige) tittel **National strategic investments in electricity transmission capacity in Europe**	

Oppgavetekst/Problembeskrivelse
Background:
Efficient energy infrastructure is necessary to facilitate trade, to reduce market power and to successfully integrate electricity generated by renewable sources in the power market. In a meshed network the benefits of new infrastructure will be distributed among several national states. Investments in infrastructure will most likely affect the welfare of national states. Thus the optimal investment decision is not necessarily the same for one national state and for an imagined supranational planner maximizing the welfare of the overall system. We want to study national strategic investments in electricity transmission capacity in Europe.

Focus areas:
- Study the European power market and the role of transmission infrastructure
- Study the role of different technologies in the power market
- Develop a mathematical model to represent different national strategic considerations in transmission expansion
- Collect relevant data for the model and implement it in GAMS
- Discuss the results and the usefulness of the model(s) and method(s)
- Try to formulate relevant policy recommendations based on research insights

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20/05 - 2019

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Originalen lagres i NTNUs elektroniske arkiv. Kopi av avtalen sendes til instituttet og studenten.

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Oppgavens (foreløpige) tittel
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4. Bedømmelse

Kandidatene skal ha *individuell* bedømmelse ☐
Kandidatene skal ha *felles* bedømmelse ☒

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Preface

This is our Master's Thesis in Managerial Economics and Operations Research at the Department of Industrial Economics and Technology Management (IØT), at the Norwegian University of Science and Technology (NTNU).

During the last five months at NTNU we have learned a lot about what for us was an entirely new issue, and realized that the issue of transmission expansion is very wide-encompassing. The work has been challenging and rewarding. We have had the chance to utilize both technical and economic expertise, and believe this thesis represents the knowledge we have gained during our studies well.

We would like to thank our supervisors, Professor Asgeir Tomargard and Associate Professor Ruud Egging for support and feedback during the project work. Special thanks goes to Jonas Egerer for introducing us to the concept of national strategic investments in transmission capacity. We would also like to thank Dr. Steven Gabriel for an excellent introduction to complementarity modeling during the EnerTrain 2013 at the Technische Universität Berlin, and to Seksun Moryadee and Pao-Yu Oei for valuable GAMS workshops.

Trondheim, June 6, 2014

Frida Arnesen Aamot　　　　Marianne Ytterbø

Sammendrag

Oppgraderinger av overføringsnettet for elektrisitet kan forårsake reallokering av samfunnsøkonomisk overskudd. Selv om det er mulig å bestemme en optimal plan fra et overnasjonalt perspektiv fører endringene i fordeling av samfunnsøkonomisk overskudd til at slike planer ikke nødvendigvis er optimale for de individuelle nasjonene. Utvidelser av nettet i Europa blir i hovedsak planlagt av nasjonale planleggere og det er en fare for at disse kan planlegge nettverksutbygging strategisk for å maksimere sitt samfunnsøkonomiske overskudd.

Vi presenterer en modell med to nivå og tidsperioder. Modellen har en nettverksplanlegger som leder og et elektrisitetsmarked som følger. Vi sammenligner en overnasjonal og en nasjonal planlegger. Den overnasjonale planleggeren maksimerer samfunnsøkonomisk overskudd i hele markedet, mens den nasjonale planleggeren maksimerer overskuddet i sitt land. Vi modellerer også to ulike kostnadsdelingsmekanismer. I det første tilfellet betaler den nasjonale planleggeren alle kostnadene knyttet til oppgraderingene den planlegger. I det andre tilfellet ser vi på bilateral kostnadsdeling. Modellen for den overnasjonale planleggeren reduseres til et kvadratisk optimeringsprogram, mens den nasjonale planleggeren modelleres med et Mathematical Program with Equilibrium Constraints (MPEC) med en ikkelineær og ikke-konveks målfunksjon. Vi reformulerer komplementaritetsbetingelsene som beskriver mulighetsområdet med en disjunktiv tilnærming. Modellene blir implementert i GAMS og løst med solverne CONOPT og BARON. Modellene er testet på et nettverk med fire og seks noder som representerer land i Nord-Europa. Vi tester også modellen med tidsperioder som representerer årene 2010 og 2020. MPECen løses til optimalitet for små instanser.

Resultatene illustrerer at ulike planleggere legger forskjellige planer som gir ulik allokering av samfunnsøkonomisk overskudd. Løsningene for de nasjonale planleggerne kommer nærmere løsningen til den overnasjonale planleggeren når vi introduserer bilateral kostnadsdeling. Vi illustrerer viktigheten av å inkludere tidsperioder for å kunne forlenge planleggingshorisonten ved å vise at en plan basert på systemet i 2010 ikke lenger er optimal for systemet i 2020. Det bør forskes mer på å forstå samfunnsøkonomiske reallokeringer som følge av investeringer i overføringsnettet og man bør bruke kunnskapen til å designe kompensasjonsmekanismer for å gjøre overnasjonale planer akseptable for nasjonale planleggere.

Abstract

Optimal transmission expansion plans can be determined from a pan European point of view, but investments in transmission capacity are likely to cause reallocations of welfare. Thus the optimal plan determined by a supranational planner is not necessarily optimal for each individual nation. Moreover, network planning is mainly done at a national level in Europe. This makes it possible for nations to plan investments strategically to maximize the welfare in their country.

We present a bi-level model with time periods to study national strategic investments in transmission infrastructure. The model has a transmission planner on the upper level and an electricity market on the lower level. We compare a supranational planner and a zonal planner. The supranational planner maximizes the welfare of the entire market and the zonal planner maximizes the welfare of her zone. For the latter case we consider a situation where the zonal planner incurs the full cost of the planned network upgrades and a bilateral cost sharing situation. The model for the supranational planner can be reduced to a quadratic optimization program, but the zonal planner is modeled using a mathematical program with equilibrium constraints (MPEC) and a non-linear and non-convex objective function. We reformulate the complementary constraints of the feasible region using disjunctive constraints. The models are implemented in GAMS and solved using the CONOPT and BARON solvers. We apply the models to a four- and six-node network representing countries in Northern Europe, and time periods representing the years 2010 and 2020. The MPEC is solved to optimality for small problem instances.

The results illustrate that different planners create dissimilar optimal plans. The various plans result in different allocations of social welfare, however the results from the zonal planner comes closer to the supranational results when the costs of transmission investment are shared bilaterally. The importance of time periods to include a long term perspective in transmission planning models is illustrated by showing that a plan for the current system state is no longer optimal in a future system state. Research effort should be put into understanding the welfare reallocations associated with network upgrades and compensation mechanisms should be designed in order to make the supranationally optimal solutions incentive compatible for national transmission planners.

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Chapter 1

Introduction

With the EU Road Map 2050 the EU is committing to working towards a low-carbon future. This decarbonization will require a transformation of the mix of fuels used for power generation, increased energy efficiency and demand response as well as expansions of the power transmission system. The EU is also seeking to promote the free movement of the "four freedoms," people, goods, services and capital through the Internal Market or Single Market. Efficient infrastructure is required for the Internal Market to work for the electricity supply industry. In particular, cross border interconnectors are needed to facilitate trade between different nations. Congested interconnectors are limiting trade and give rise to opportunities for strategic behavior for various market players. Moreover increasing transmission capacity in a meshed network is likely to cause re-allocations of social welfare between countries.

As transmission planning is mostly done at a national level one could assume that national planners will plan investment decisions to maximize the welfare in their respective countries. Furthermore one could assume that different national planners will provide dissimilar optimal plans and that these plans will differ from a pan European optimal plan. We use the term national strategic for the possible strategic behavior by nations when planning transmission expansions. Our use of the term is similar to Huppmann and Egerer (2014).

Our thesis is motivated by the distributed nature of benefits arising from transmission investments and the possibility of national strategic investments. We will analyze this using a bi-level model for transmission expansion.

1.1 Main Contributions

Our master's thesis has three main contributions.

1.1.1 An MPEC for Transmission Planning with Time Periods

We present a model with a transmission planner on the upper level and an electricity market on the lower level. The transmission planner maximizes social welfare defined as the sum of producer and consumer surplus, by investing in transmission capacity. We consider both a supranational planner maximizing the welfare of all nodes included in the market and a zonal planner which maximizes the welfare of one zone. We utilize the aligning objectives of the upper and lower level to model the supranational planner's problem as a single level optimization problem. For the zonal planner the objectives does not align and we present a mathematical problem with equilibrium constraints to model the zonal planner's problem. To include the long term perspective of transmission investments we have added time periods to the model.

1.1.2 Application of the Models on the Northern European Electricity Market

We apply the model on a data set representing countries in Northern Europe in 2010 and 2020. The 2020 data is based on trends presented in The EU Energy Trends to 2030 (European Comission (EC), 2009) and other reports. We compare the solutions for a supranational planner, a zonal planner without cost sharing and a zonal planner with bilateral cost sharing to a benchmark case which represents the original market outcome without transmission investments. We highlight the developments in welfare allocation.

1.1.3 Implementation and Solving of the Models in GAMS

Both the optimization problem representing the supranational planner and the MPEC representing the zonal planner are implemented in GAMS. The optimization problem solves easily for the problem instances we have tested.

The MPEC representing the zonal planner is non-linear and non-convex. We use a disjunctive constraint approach to represent the complementary constraints of the lower level and demonstrate that we are able to solve the problem to optimality using the BARON solver (Sahinidis, 2013) in GAMS.

1.2 Overview of Thesis

This thesis starts by a brief discussion of some relevant themes to give some background knowledge and a review of related literature before we present two transmission expansion models. The models are presented in chapters 4 and 5. Chapter 4 presents the model representing a supranational planner. This planner is maximizing the welfare for all nodes. Chapter 5 presents a model for a zonal planner. This planner maximizes the welfare for an individual node. For this planner we consider a situation where the node planning the investments incur all the costs and a bilateral cost sharing situation where the costs of an interconnector are shared by the countries on either side of the line.

Relevant data is collected and presented in Chapter 6 before we introduce the implementation and results in Chapters 7 and 8. Chapter 9 includes a discussion of the limitations of the model and the validity of the results. We also translate research insights into policy recommendations and give some suggestions for further work before we give some concluding remarks in Chapter 10.

Chapter 2

Background

2.1 Electricity

It is necessary to understand the physical characteristics of electricity and the interactions in the value chain to understand electricity markets and the behavior of the different agents. Some physical characteristics of electricity are discussed in Subsection 2.1.1. Subsection 2.1.2 gives an introduction to the electricity value chain and some background on the ongoing electricity market liberalization is given in Subsection 2.1.3. The section concludes with an introduction to transmission expansion issues in Subsection 2.1.4.

2.1.1 Physical Characteristics of Electricity

Electricity cannot be stored, meaning it has to be produced and consumed at the same moment in time. The transportation of electricity requires physical connections, transmission lines. The flow on these lines is continuous, much like the flow of gas in natural gas pipelines. The flow of electricity is determined by Kirchoff's current and voltage laws, and the flow pattern is determined by injections and withdrawals at nodes. We have *system effects* in the sense that injections or withdrawals at one node affects the flow in other parts of the network. Basically, this defines an "unvalved" network where power flows on all possible paths between a source and a sink. The flows cannot be directed. This leads to the problem of loop flows. When electricity is supposed to be transported from A to B in a network like the one illustrated in Figure 2.1, some will go directly from A to B, but some will also go via C. These physical transmission limitations can be modeled using the linearized DC load flow equations. This approach represents the AC grid with a DC-like representation[1], resulting in a simplified representation of electricity networks, as resistances in the transmissions lines are neglected and voltage angles are assumed to be small. However the loop flows are represented in a good way when using the DC load flow approach.

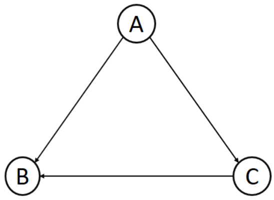

Figure 2.1: Three node loop flow example

2.1.2 The Electricity Value Chain

The electricity value chain consists of suppliers of energy sources or fuels, generators, transmission system operators, distributers and final consumers. This is illustrated in Figure 2.2.

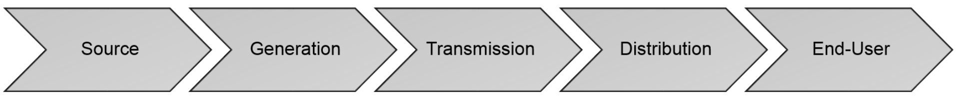

Figure 2.2: The electricity value chain

We usually differentiate between fossil and renewable energy sources. The various energy sources have different degrees of variability and flexibility. Since electricity has to be produced and consumed at the same moment in time, and electricity demand is inelastic in the short term and varies through the day, week and season, flexibility is a desired property of an energy source. When the power production is flexible it is easier to match supply and demand. Variability is less desirable as this makes the task of matching supply and demand more difficult.

Traditional thermal units are not variable, but have constraints like start-up costs, restrictions on minimum up-and downtime and ramping restrictions, meaning they are not very flexible either. When a turbine is turned on it will run until it is turned off, but it takes time to turn it on and off. Due to their low variability and

[1] AC is an abbreviation for alternating current, and means that the flow direction of the electric charge periodically changes. With a directed current (DC) the flow of the electric charge only takes one direction. Power is usually distributed as AC, and this is the form the electric power in regular houses is delivered. If the power is to be transmitted over large distances it will sometimes be transformed in to DC.

flexibility, thermal units with low marginal costs are usually used to cover the base load. Thermal units with high marginal costs are usually used to cover peaks.

Hydro power is more flexible than thermal units. It is not very variable either, however the generation output is proportional to the head, which will be reduced if the reservoir is emptied. Thus the scheduling of hydro power has to take into account the filling degree in the reservoirs. The reservoirs are filled by inflow and rain and emptied when the water is used to produce power or if the reservoir overflows. The power is sold at the electricity price. Thus hydro power planning becomes a question of when to use the water to produce power in order to maximize the value of the water, i.e the price the hydro power can be sold at. If the reservoir is overfilled and the water flows over, the value of the water goes to zero. This means the owner of the power plant would like to produce power when the price is high, but at the same time make sure no water is lost due to overfilled reservoirs. This results in a dynamic planning problem. Long term hydro power scheduling is a stochastic dynamic optimization problem. This is described in Wolfgang et al. (2009).

Wind and solar power are examples of variable generation. The generation from these units is dependent on climatic factors. A wind farm produces power when the wind blows and a solar power plant produces power when the sun shines. This variability and lack of flexibility is difficult to handle in the power market. Wind power in particular creates new flow patterns accross grids (Brunekreeft et al., 2005). Furthermore the geographical location of these sources can be far from consumption centers. This means increased transmission capacity will be needed to transport the power from where it is produced to where it is consumed. Thus increasing amounts of variable power in the power market increases the need for transmission capacity.

The transmission system operator (TSO) is responsible for transmitting the electrical energy from power producers to substations near the final consumers. The distributers distribute power from the substations to the final consumers. The transmission from power producers to substations is usually done at a high voltage level, whereas the distributers transform the power to a lower voltage level before distributing it to final consumers.

2.1.3 Electricity Market Liberalization

The ongoing liberalization of the world energy markets started in the late 1980's. These markets were formerly characterized by imperfect competition, but are now in the process of being restructured into competitive industries. In practice liberalization usually implies privatization and sale of state owned assets under the assumption that privatization will improve economic efficiency (Kopsakangas and Svento, 2012). Historically the generation companies were vertically integrated and controlled both generation, transmission and distribution. With this vertical integration of the power sector investments in new interconnectors were mainly done to increase the reliability of the grid as economically as possible.

One important feature of the restructuring is the unbundling of the power system in competitive and non-competitive parts. Electricity distribution is generally considered to be a natural monopoly due to economies of scale (Wangensteen, 2007). Generation on the other hand is not considered to have significant economies of scale.[2] Thus the power markets were unbundeled into one competitive part comprising generation and consumption, and monopolistic transmission and distribution. Further, the network operators were obliged to allow third party access to the infrastructure. This open access to the grid enables all generators and consumers to use the grid for transportation. The grid now represents a physical marketplace for competitive trade (Wangensteen, 2007). Thus an efficient and robust transmission infrastructure is imperative for the liberalization of the power market. Insufficient transmission capacity will adversely affect the degree of competition in the power market. Green and Newberry (1992) addressed the issue of market power for England and Wales where two players, National Power and PowerGen, were able to offer supply considerably above marginal cost, and had the opportunity to exploit the transmission grid constraints. The analysis suggested that market power were underestimated by the government when designing the market. Lise et al. (2008) use the static computational game theoretic model COMPETES to investigate market power in the European electricity market and find that increased transmission capacity would lower the prices in countries with high prices and reduce the impact of market power.

Liberalization of the power sector also causes new flow patterns across the grid when consumers are able to chose their supplier. These grids were originally designed to provide security of supply to countries with moderate imports. The new market driven flows pose new challenges to the grid as it needs to accommodate more market-responsive trading.

2.1.4 Transmission Expansion

In the previous sections we have seen that an increasing share of variable energy sources in the power market and the liberalization of the energy markets is driving a need for increased transmission expansion. Brunekreeft et al. (2005) gives an overview of the current debate on electricity transmission by organizing a large set of questions in four overcharging issues which we will discuss below.

The first is the question of whether locational marginal pricing (LMP), also called nodal pricing, provide efficient long term investment signals to generators and consumers. Grid charges should ideally encourage efficient short-run investments and use of the network, efficient signals to guide generation investment decisions and at the same time be fair, politically feasible and encourage cost recovery. Thus

[2] Although the price per kWh usually is higher in a small generation unit than a large one, the economies of scale is usually not considered to be significant enough to preclude competition.

setting these charges at the right level is quite difficult, but nevertheless critical for efficient use and development of the grid.

If LMP does not provide adequate market signals, additional differences in grid charges will be required. We differ between deep and shallow connection charges. The latter refers to a situation where power producers only pays the cost of connecting their plant to the nearest grid, whereas the system operator pays for any necessary reinforcements in the grid. This minimizes the costs for the power producers and gives incentive to choose locations based on resource availability instead of on grid availability. With deep connection charges the power producers are responsible for paying both connection and reinforcement costs. This increases the costs for the power producers and gives incentive to locate production based on grid availability. Shallow connection charges are usually preferred, but deep connection charging can become necessary if LMP does not cover fixed network costs sufficiently.

Second comes the question of whether market coupling will work in Europe. Previously cross border trading was done mainly to ensure reliability and security of supply in times of power shortages. Nowadays the transmission capacity is used for trade. Initially this trade was organized locally and only between interconnected countries. They traded transmission capacity and electricity separately. Transmission capacity was explicitly auctioned and electricity was traded in a separate market place. The idea of market coupling is that this trade can be done more efficiently on a pan European level if power exchanges and TSOs work together to couple the trade of electricity and transmission capacity through so called implicit auctioning. This follows naturally from the general liberalization of energy markets and the perception that market based mechanisms are required.

When trade is coupled the individual TSOs determine the amount of transmission capacity available for trade and announce this. Power exchanges matches demand and supply for electricity and a joint market coupling system determines the price and the amount of electricity to be imported or exported. This has been done in Scandinavia since 1993. In 2006 France, Belgium and the Netherlands coupled their markets followed by Germany and Denmark in 2009. In 2010 all these countries, including some Baltic states coupled their markets. Better pan European market coupling is intended to provide greater security of supply, better utilization of transmission capacity, more stable electricity prices.

An alternative to market coupling as a means of handling cross border congestion favored by some parties, is a move towards more refined coordinated auctions.

The third issue is merchant investments. Some interconnectors are highly profitable. For example the NordNed HVDC cable between Norway and the Netherlands earned 100 millions € of revenues during its first year of operation in 2008 (Doorman and Frøystad, 2013). Investment costs of new capacity have traditionally been paid nationally by the countries making the investment. Costs of cross-border lines have been shared bilaterally. With this cost allocation, some countries may end up paying for other countries' benefit. Since each country decides his own investments all cooperation needs to be incentive compatible and rational. Merchant investments mitigates the need for voluntary agreements between the TSOs on either side of the interonnectors, but raises new regulatory issues.

The fourth and final issue is the need to better understand how to design incentive mechanisms for TSOs. It is important to find mechanisms which do not incentivice TSOs to increase costs rather than decrease them. Brunekreeft et al. (2005) calls the understanding of this issue underdeveloped.

2.2 Energy Infrastructure in the European Union

> *Energy infrastructure is key to all our energy goals: from security of supply, the integration of renewable energy sources and energy efficiency to the proper functioning of the internal market. It is therefore essential that we pull together our resources and accelerate the realization of EU priority projects.* - EU Comissioner for Energy, Günther Oettinger [3]

The European Union internal market seeks to guarantee the free movement of the EU "four freedoms," goods, capital, services and people within the EU member states. For this market to work for electricity, an efficient and robust energy infrastructure is required. The goal is to balance demand and supply across borders rather than focusing on national markets.

Furthermore European energy infrastructure is in need of upgrades to be suited to match future demand for energy, provide adequate security of supply and to support the integration of renewable energy in the energy mix.

Figure 2.3 gives an overview of the European energy infrastructure priorities. Improvements in the North Seas Offshore grid are needed to include production capacity in the northern seas and the Scandinavian peninsula in the European power market. Improved interconnections in the South Western and Central and South Eastern parts of Europe are needed to assist the integration of these markets in the European internal market and for the integration of renewable energy in the energy mix. The Baltic Energy Market Integration Plan (BEMIP) comprises both gas and electricity and is a plan for better integration of the Baltic countries to wider EU energy networks.

[3]http://europa.eu/rapid/press-release_IP-10-1512_en.htm?locale=en

Figure 2.3: European energy infrastructure priorities for electricity

The investments for the following decade are included in the European *Ten Year Network Development Plan* (Entsoe, 2014c). Some *Projects of Common Interest* (PCI) have been recognized by the European Commission (European Comission, 2014). These projects provide significant benefit for at least two member states and will benefit from faster granting procedures as well as access to additional financial support. The EU has also introduced the Inter TSO compensation mechanism (European Comission, 2010a) which is intended to compensate TSOs for hosting transit flows.

2.3 Game Theory

This section aims to introduce some important concepts for this thesis and is by no means meant to provide an exhaustive overview of the field of game theory.

Game theory strives to formalize the theory and mathematics describing strategic interactions between agents. A game in this context consists of the following three elements: A set of players, a set of actions or strategies and a set of pay-off or utility functions for each player. Game theory differs from conventional economic theory in the sense that players anticipate the reactions of other players and consequences of their own choice. A player's pay-off depends on its own actions and the choices made by other players. Furthermore it is assumed that all players are rational in an economic sense. A player will never intentionally choose to make a choice leaving her worse off. At the same time the player knows that all other players also are rational.

Game theory makes more sense with few players. It is hard to believe that a single player will take into account the actions of an infinite amount of other players. This is often handled by considering just a few players and then allocating the rest of the market to a *competitive fringe* which is assumed to act as perfect competition.

Modern day game theory is based on the classical work by Cournot (1838) and von Neumann and Morgenstern (1944). The economist John Nash wrote the famous Nash papers (Nash, 1950, 1951) and the notion of *Nash equilibrium* has become important in analyzing a wide range of situations, spanning from politics to biology and artificial intelligence. In a Nash equilibrium it is assumed that the players can impact the other players pay-off by their choice of strategy, but given the other players choice of strategy, no player has an incentive to change their own choice of strategy. If a Nash equilibrium exists, this is a stable solution to a game.

To find equilibrium solutions one look for dominant strategies. Say we have a set of players $i \in I$. These players have a set of pure strategies, $x_i \in X_i$. Pure strategy simply means the player chooses one of the strategies with probability 1. A player plays mixed strategies if he chooses strategies with a probability distribution. The utility of player i is given by its utility function $u_i\left(x_i\right)$. A strategy is strictly dominant if $u_i\left(x_i, x_{-i}\right) > u_i(x_i', x_{-i})$, where x_i and $x_i' \in X_i$ and $x_{-i} \in X_{-i}$ denotes the set of strategies with the i'th element removed. A weakly dominant strategy exists if $u_i\left(x_i, x_{-i}\right) \geq u_i(x_i', x_{-i})$ and $u_i\left(x_i, x_{-i}\right) > u_i(x_i', x_{-i})$ for at least one $x_i \in X_i$ (Jackson, 2011).

An extension to the Nash equilibrium is the Generalized Nash Equilibrium, first formally introduced by Debreu (1952) and further developed in Arrow and Debreu (1954). In the Generalized Nash Equilibrium Problem (GNEP) the players can impact both the other players pay-off and their set of feasible strategies. GENEPs arise quite naturally from Nash equilibrium problems (NEP) when players share a common resource or have some joint constraints (Facchinei and Kanzow, 2007). For example transmission networks with capacity restrictions. GNEPs are usually very difficult to solve due to lack of uniqueness in the solutions.

We differentiate between cooperative and non cooperative games. In cooperative games players form groups engaging in cooperative behavior and the resulting game is between coalitions of players rather than between individual players.

We also differentiate between constant sum games and non-constant sum games. In constant sum games the sum of the profits for the individual players is constant, but the distribution of profits can vary. In non-constant games the sum of payoff depend on the strategies chosen. Such games can encourage cooperative behavior if the players know the sum of payoffs. In other words the size of the pie, can be changed.

One famous example of a non-constant, non-cooperative game is the prisoners dilemma. This is a game where two players can choose between two strategies; A and B. The sum of payoffs is highest if both players choose strategy A, but each individual player will have a higher payoff if he chooses strategy B. Thus the stable outcome is for both players to choose strategy B and thus making both worse off.

Another important concept is the Stackelberg game which is a sequential game. This game formulation works well for modeling games with sequential moves or leader follower relationships. It is a bi-level game. One standard solution method is backward induction where first the leader's decisions are fixed, then the follower's reaction function are found using their first order optimality condition. A reaction function describe a players best response given another players move. This is used to derive the optimization problem for the leader which is constrained by the response of the followers.

When the lower level problem's first order optimality conditions are inserted into the upper level problem as constraints, the decision variables for the lower level problems, mathematically speaking, becomes decision variables of the upper level problem. This is not a problem when the lower level response is unique for all upper level decisions. However if the lower level is indifferent between a set of responses, given the upper level's decision, this approach implicitly assumes the lower level will choose to do what is best for the upper level. This is thus an optimistic approach to modeling bi-level games. In pessimistic bi level games the lower level will choose the response yielding the worst outcome for the upper level. Such a situation could occur if the upper and lower level players are rivals.

2.4 Mathematical Modeling of Power Markets

There are several different approaches to mathematical modeling of energy markets. Many are based on optimization theory, equilibrium theory or both. Ventosa et al. (2005) identify three major modeling trends in electricity market modeling; optimization, equilibrium and simulation models. Subsection 2.4.1 gives an introduction to optimization, and Subsection 2.4.2 summarizes some equilibrium modeling approaches. In general an optimization model finds the optimal decision for one firm, whereas equilibrium models search for a market equilibrium where no player has an incentive to change her decision given the other players decisions. The equilibrium solution is not necessarily a globally optimal solution. Consequently searching for an optimal solution is usually harder when faced with an equilibrium problem than an optimization model.

2.4.1 Optimization

The field of optimization belongs to the field of applied mathematics and seeks to facilitate optimal decisions using mathematical methods and models. The optimal decisions will usually be the decisions maximizing or minimizing an objective function of its arguments subject to a set of constraints. The general set-up is:

$$\max_x f(x) \tag{2.1a}$$

$$s.t. \quad g_i(x) \leq 0 \quad \forall i \in I \tag{2.1b}$$

$$x \in X \tag{2.1c}$$

Where x denotes the decision variables belonging to the set X, $f(x)$ denotes the objective function and $g_i(x)$ the i'th constraint. The complexity of the objective function (2.1a) and the constraints (2.1b) and (2.1c) vary, and defines different classes of optimization problems. If all functions (f, g_i) are linear and all variables are continuous ($x \in R^n$) we call the optimization problem a linear programming problem (LP). (Lundgren et al., 2010) Every LP problem has an associated dual problem which is defined by the same input data as the primal problem. The following linear program:

$$\min_x c^T x \tag{2.2a}$$

$$s.t. \quad Ax \geq b \tag{2.2b}$$

$$x \geq 0 \tag{2.2c}$$

has the corresponding dual:

$$\max_y b^T y \tag{2.3a}$$

$$s.t. \quad A^T y \leq c \tag{2.3b}$$

$$y \geq 0 \tag{2.3c}$$

The Weak Duality theorem for LP's states that the primal and dual objective function values are bounded on each other for a pair of feasible vectors, x, y, such that $c^T x \geq b^T y$. The Strong Duality theorem states that if x and y are feasible and $c^T x = b^T y$ we have found the optimal solution. (Lundgren et al., 2010)

In some sense these primal and dual aspects can be considered an equilibrium problem where the two problems represent different players controlling different variables. In this case one player controls x and the other player controls y. In optimum there is a balance between the competing players objective function values. This concept extends to nonlinear programs as well if the objective function is convex in a minimization problem, or concave in a maximization problem, and the constraints meet certain constraint qualifications. If the objective function and the feasible region defined by the constraints are convex, the problem is convex. When this is the case each local optimum will also be a global optimum. Thus one constraint qualification is to have a convex feasible region. However this does not always hold. Other constraint qualifications are for instance the Abadie and the Guignard constraint qualifications. See for instance Flegel and Kanzow (2004) for a discussion of these.

The Karush-Kuhn-Tucker (KKT) Conditions are necessary and sufficient optimality conditions in mathematical programming, given certain problem requirements. They describe the characteristics of the optimal solution and can support the development of solution algorithms to nonlinear programs (Lundgren et al., 2010).

Consider the following general maximization problem:

$$\max_{x} f(x) \tag{2.4a}$$

$$s.t. \quad g_i(x) \leq b_i \quad (\lambda_i)\,,\ \forall i \in I \tag{2.4b}$$

$$h_j(x) = 0 \quad (\gamma_j)\,,\ \forall j \in J \tag{2.4c}$$

$$x \geq 0 \tag{2.4d}$$

where λ_i and γ_j represents the Lagrangian multipliers for the constraints. Every restriction has an associated multiplier, and the multiplier expresses how much the objective function value will change if the right hand side of the restriction is increased by one unit. If the objective function (2.4a) is concave and the feasible region described by (2.4b) - (2.4d) is convex, the KKT conditions are necessary and sufficient conditions for optimality. The KKT conditions for the minimization problem in 2.4 are expressed below in Equations 2.5.

$$\nabla f(x) + \sum_i \lambda_i \nabla g_i(x)^T + \sum_j \gamma_j \nabla h_j(x)^T = 0 \tag{2.5a}$$

$$\lambda_i \geq 0 \qquad \forall i \in I \tag{2.5b}$$

$$g_i(x) \leq b_i \qquad \forall i \in I \tag{2.5c}$$

$$h_i(x) = 0, \quad \gamma_j, \quad free \qquad \forall j \in J \tag{2.5d}$$

$$\lambda_i \left(b_i - g_i(x)\right) = 0 \qquad \forall i \in I \tag{2.5e}$$

The first set of equations (2.5a)-(2.5e) ensures dual feasibility as $\nabla f(x)$ is stated as a non-negative linear combination of the constraint gradients. (2.5c) and (2.5d) ensures *primal feasibility*. The solution has to be feasible to be optimal. The final constraint (2.5e) defines *complementarity* and states which set of constraints that are active in the solution x.

We have seen that optimization can be used to find the best decisions to maximize or minimize an objective function. Further we have seen that the primal and dual aspects of optimization have relations to equilibrium and that the KKT conditions are necessary and sufficient optimality conditions for convex problems. Consequently optimization models can successfully be used to model energy markets. However this approach requires the players objective to be consistent with one overall objective. This assumption is not valid in the presence of market power, as the perfect competition approach no longer can be used (Gabriel et al., 2012). This leads us to complementarity modeling.

2.4.2 Equilibrium Modeling

Equilibrium modeling aims at finding the equilibrium state. A form of the equilibrium state can be different competition equilibriums such as the Nash-Cournot Equilibrium. By the help of equilibrium models, one may be able to predict how the system will look like in the future or how it will respond when introduced to changes.

Equilibrium problems can be modeled using complementarity problems. When doing this the dual as well as the primal variables are used. Figure 2.4 gives an overview of various classes of complementarity problems. Both linear programs (LP) and quadratic programs (QP) are convex, thus the KKT conditions are necessary and sufficient conditions for optimality for these problems. Non-linear programs (NLP) are not necessarily convex, but if they are, the KKT conditions are necessary and sufficient conditions for these as well. Other non-optimization based problems like spatial price equilibria, traffic equilibria and Nash-Cournot games are also examples of complementary problems. Mixed complementarity problems (MCP) is an umbrella term for the mentioned problem classes. Figure 2.4 summarizes this.

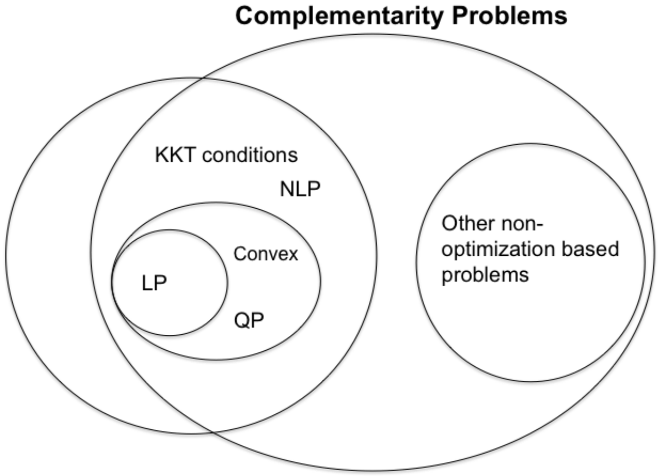

Figure 2.4: An overview of complementarity problems (Gabriel, 2013)

Mixed Complementarity Problems

The idea of equilibrium modeling is to solve several optimization programs simultaneously to find an equilibrium where all agents are happy. In complementarity models we are able to involve both the primal variables (e.g. production levels) and dual variables (e.g. market prices) in the model formulation. Traditional optimization models do not handle this mixing of variables (Gabriel et al., 2012).

Gabriel et al. (2012) states the most common representation of a mixed complementarity problem (MCP) as follows: Having a function $F : R^n \to R^n$, MCP(F) is to find vectors $x \in R^{n_1}, y \in R^{n_2}$ such that for all i:

1. $F_i(x, y) \geq 0,\ x_i \cdot F_i(x) = 0,\ i = 1, ..., n_1$
2. $F_{j+n_1}(x, y) = 0,\ y_j\ free,\ j = 1, ..., n_2$

Mathematical Programs with Equilibrium Constraints

An extension to MCPs are bi-level problems. Bi-level models are characterized by a hierarchical relationship between two autonomous decision makers. Two problems are included in one instance and one of the problems are part of the constraints of the other. An overview of bi-level optimization is given in Colson et al. (2007). When an optimization problem is constrained by an equilibrium problem it is often referred to as a *Mathematical Program with Equilibrium Constraints* (MPEC). Gabriel et al. (2012) gives the following general representation of MPECs:

$$\max f(x, y) \tag{2.6}$$

$$s.t. \;\; x, y \in \Omega \tag{2.7}$$

$$y \in S(x) \tag{2.8}$$

In the example above x represents some upper-level decisions (e.g. production level) for a dominant player and y represents some lower-level decisions. The lower-level decisions (e.g. the market) arise from an equilibrium problem. Thus the upper-level player's decisions are constrained by the lower-level equilibrium problem. MPECs are useful for modeling leader-follower equilibria a la von Stackelberg (1952). Chen et al. (2004) formulate a large scale MPEC to analyze a Stackelberg game where the largest producer in an electricity market has the ability to manipulate both the electricity and emissions market to its advantage. Gabriel and Leuthold (2010) use an MPEC formulation to solve a Stackelberg game for a network-constrained energy market.

2.4.3 Equilibrium Problems with Equilibrium Constraints

An equilibrium problem with equilibrium constraints, EPEC, is a program where several MPEC's are to be solved. This is typically used when one wish to model markets where there is more than one leader and we need to model multiple leader-common follower games.

Common solution procedures for EPECs are *enumeration* and *diagonalization*. Enumeration simply finds all possible solutions whereas diagonalization is a version of the Gauss-Seidel algorithm and solves each MPEC consecutively (Gabriel et al., 2012).

2.4.4 Solving Mathematical Problems with Equilibrium Constraints

The problem with MPECs is that they are in general non-convex and non-differentiable. Thus they violate most standard constraint qualifications and standard algorithms cannot find a guaranteed optimal solution, even if the objective function is strongly convex. Also, any smooth reformulation of the complementarity constraints violates the Mangasarian- Fromovitz constraint qualification, which is crucial for stability (Chen et al., 2004). Nevertheless several decomposition and relaxation approaches have been developed in order to solve MPECs.

One common solution approach is to linearize the lower level KKT conditions using disjunctive constraints. This is done in Gabriel and Leuthold (2010). However disjunctive constraints are computationally expensive. Furthermore the approach requires the modeler to select appropriate values for constants used in the constraints, which can be challenging. Siddiqui and Gabriel (2012) therefore use Schur's decomposition and SOS1 type variables to linearize the constraints in the lower-level problem, and show that this method computationally outperforms other methods.

Disjunctive Constraints Approach

The disjunctive constraints approach, introduced by Fortuny-Amat and McCarl (1981), replaces equilibrium constraints by integer restrictions in the form of disjunctive constraints. This transforms the MPEC into a mixed integer linear program (MILP) or a mixed integer non-linear program (MINLP), which is easier to solve than an MPEC. MILP problems are fairly straight forward to solve, provided the number of integer variables is not *too large*.

Given an MPEC where the lower level problem is a complementary problem:

$$minf(x,y) \tag{2.9a}$$

$$s.t.(x,y) \in \omega \tag{2.9b}$$
$$y \geq 0 \tag{2.9c}$$
$$g(x,y) \geq 0 \tag{2.9d}$$
$$y^T g(x,y) \geq 0 \tag{2.9e}$$

The complementarity conditions can be replaced by disjunctive constraints by introducing a vector of binary variables r and parameters K.

This would give the following reformulation:

$$minf(x,y) \tag{2.10a}$$

$$s.t.(x,y) \in \omega \tag{2.10b}$$
$$0 \leq y \leq K(1-r) \tag{2.10c}$$
$$0 \leq g(x,y) \leq Kr \tag{2.10d}$$

As illustrated by equation 2.10c and 2.10d, the disjunctive constraints approach transforms an MPEC into an MINLP or MILP depending on the objective of the MPEC. There are two important drawbacks with this approach. Firstly, it is computationally expensive for large models. Although there has been great progress in the development of good MILP and MINLP solution methods and the implementation of these in solvers, such as CLPEX and Dicopt, it is still challenging to solve large integer programs. Second, the disjunctive constraints approach is very sensitive towards the selection of the K-parameters. These are problem specific and has to be neither too big nor too small, as this can cause computational difficulties. Too small K's result in a too tight formulation, and cause errors in the problem formulation. Too large K's cause the conditioning number to increase. Thus this can cause numerical errors (Siddiqui and Gabriel, 2012). Badly chosen K's can cause the solution value to differ greatly from the true answer.

SOS1-Based Appraoch

An alternative method for solving MPECs is the SOS1-Based Approach presented by Siddiqui and Gabriel (2012). They use Schur's decomposition to replace the complementarity conditions. The absolute value term introduced by Schur's decomposition is reformulated using SOS-1 variables.

Say we want to linearize the following complementary condition:

$$0 \;\leq\; x \;\perp\; y \;\geq 0 \tag{2.11}$$

First the condition can be reformulated using the variables u and v by Schur's decomposition.

$$\begin{align} x &\geq 0 \tag{2.12a}\\ y &\geq 0 \tag{2.12b}\\ u - |v| &= 0 \tag{2.12c}\\ u &= \frac{x+y}{2} \tag{2.12d}\\ v &= \frac{x-y}{2} \tag{2.12e}\end{align}$$

Second v can be reformulated using SOS-1 variables by decomposing it into its positive and negative parts: $v = v^+ - v^-$, where v^+ and v^- are SOS-1 variables. This way an exact, linear formulation of 2.11 is:

$$\begin{align} x &\leq 0 \tag{2.13a}\\ y &\leq 0 \tag{2.13b}\\ u - \left(v^+ + v^-\right) &= 0 \tag{2.13c}\\ u &= \frac{x+y}{2} \tag{2.13d}\\ v^+ - v^- &= \frac{x+-y}{2} \tag{2.13e}\\ v^+, v^- &\text{are SOS-1 variables} \tag{2.13f}\end{align}$$

Siddiqui and Gabriel (2012) report good computational results using this method.

Solving MPECs as Non-linear Problems

Some research (Fletcher et al., 2002; Fletcher and Leyffer, 2004; Leyffer, 2006) also indicate that MPECs can be solved as non-linear programs, using sequential quadratic programming (SQP). Fletcher et al. (2002) present a convergence analysis showing that SQP methods converge quadratically when applied to the NLP equivalent of an MPEC. The NLP is obtained by expressing complementary constraints of the form:

$$0 \quad \leq \quad x \quad \perp \quad y \quad \geq \quad 0 \tag{2.14}$$

as

$$x \geq 0 \tag{2.15a}$$

$$y \geq 0 \tag{2.15b}$$

$$x^T \cdot y \leq 0 \tag{2.15c}$$

This research indicate that the sequential quadratic programming approach can compute stationary points to MPECs when using a smooth reformulation of the complementary constraints.

Heuristics

Heuristic methods like generic algorithms, simulated annealing and tabu search are more flexible with respect to problem formulation and mathematical properties, like convexity. Good feasible solutions can be found, but heuristic methods cannot guarantee an optimal solution. Latorre et al. (2003) classify publications and models on transmission expansion planning and list several heuristic models. Bjus and Belmans (2012) use a generic algorithm to solve an MPEC representing a transmission planning problem.

2.5 Global Optimization

> *The field of applied mathematics that studies extremal locations of non-convex functions subject to (possibly) non convex constraints is called Global Optimization.*

(Liberti, 2008) (page 3)

Simplified, global optimization seeks global solutions of a constrained optimization model. Nonlinear models occur in many fields; e.g. in chemical engineering, data analysis, biotechnology and mathematical problems. The challenge with non convex optimization is that in the absence of convexity, the standard constraint qualifications do not hold. This means that a point satisfying the KKT-conditions can be a global minimum, local minimum, a saddle point, or even a local or global maximum. This makes finding the globally optimal solution challenging.

In recent years, there have been developed algorithms that try to tackle nonconvex problems. Exact methods for solving non convex problems include enumeration strategies, successive approximation, Bayesian and adaptive stochastic search algorithms. Heuristic strategies include globalized extensions of local search methods, evolution strategies, simulated annealing and tabu search (János Pintér).

Many of these methods are unfortunately computationally expensive. Some of the most successful algorithms for solving deterministic global optimization problems have been based on Branch-and-Select techniques. One of the first methods to deal directly with the generic non convex NLPs was Ryoo and Sahinidis' Branch-and-Reduce algorithm published in 1995 (Tawarmalani and Sahinidis, 2005). Sahinidis has used his work in this field to develop BARON, a global solver (Sahinidis, 2013).

If the nonlinear problem contain integer variables, we get a Mixed-Integer Nonlinear Problem (MINLP). This problem often occur in transmission planning and economic welfare models. Algorithms for globally solving MINLPs can be divided into two categories; deterministic and stochastic. Common for both types of algorithms are two algorithm phases; the global and the local phase. The global phase explore the search space. Regions that are known not to contain the global optimal solution are not explored. If there is a possibility that the region contain the optimal solution, the local phase is initiated. A local optimization procedure is called to identify locally optimal points. The search for solutions stop when it can be proved that no part of the feasible region can contain a better solution than the one already found. A mathematical description of a basic Branch-and-Select algorithm can be found in Liberti (2008)

Chapter 3

Literature

This chapter gives an overview of literature on transmission expansion planning in Section 3.1,and the role of transmission capacity extensions in supporting renewable energy in Section 3.2. Section 3.3 introduces some literature on transmission expansion modeling. The chapter concludes with some literature on national strategic investments in transmission infrastructure in Section 3.4.

3.1 Transmission Expansion Planning

The need for better coordination of investments on a European level is pointed out by among others Meeus et al. (2006) and Buijs et al. (2010). The latter discuss seams issues, i.e. trade across boundaries with other TSOs, in European transmission investments. The need for investments will require voluntary cooperation between countries. However supranational thinking is unlikely in the current framework. In order to go beyond the current suboptimal situation, national and European goals need to be better aligned. The same issue is discussed for the US by Benjamin (2007).

Brunekreeft et al. (2005) stress that electricity transmission is critical for successfully liberalizing power markets and for being able to extend the European Single market to electricity, and point out better incentives for TSOs, especially with respect to cross-border issues, as a key issue for further research.

3.2 Interconnectors and Renewable Energy

As was discussed in Subsection 2.1.2 increasing shares of variable energy sources in the energy mix are difficult to handle in the power system because stochastic supply has to balance with demand. Interconnectors will have an important role in supporting renewable energy.

Schaber et al. (2012a) use a regional power system model to examine the effect on the power market from increasing shares of variable energy sources in the European power system. They find that grid extensions are economically very advantageous for both base load and variable renewable energy utility owners, and show that transmission extensions reduce the market effect of large quantities of renewable energy. In a following paper Schaber et al. (2012b) find that grid extensions can reduce the need for expensive backup generation and electricity storage.

Scorah et al. (2012) study the interaction of a hydro power dominated power system (British Colombia) and a thermal dominated system with increasing shares of wind power (Alberta). They find that better integration between the markets mutually benefit the two systems. On the one hand the thermal system support the hydro system during drought and on the other hand the hydro reservoirs serve as storage for the wind power.

Fürsch et al. (2013) iterate an investment and dispatch optimization model with a load flow based grid model to quantify the benefits of optimal transmission grid extensions in Europe until 2050. They find that deployment of renewable energy in favorable sites is cost effective, even when including the costs for transmission grid extensions.

3.3 Transmission Expansion Modeling

The network expansion problem is in nature a complex multi-period, multi-objective problem, and is consequently difficult to solve. Latorre et al. (2003) gives an excellent overview of various publications and models on transmission expansion planning. They classify publications by solution methods, the treatment of the planning horizon and the consideration of the new competitive schemes in the power sector. The solution methods are mainly mathematical optimization methods or heuristic methods.

As was discussed in Section 2.1.1, physical exchange of electricity impact the whole system. Commercial trading on the other hand is bilateral. Schweppe et al. (1988) represent one of the first attempts to integrate load flow in transmission expansion modeling. Since the DC load flow approach have become quite common in power transmission modeling.

Garcés et al. (2009) use a bilevel approach to transmission expansion planning where the upper level represent the TSO and the lower level represent a number of market clearing scenarios. The objective of the upper and lower level is social welfare maximization. They utilize the aligning objectives to reduce the problem to a single level problem and recast this as a mixed integer linear program which they test on a 24-bus system.

Suma and Oren (2007) look at transmission expansion planning with different objectives in order to consider different economic criteria for planning. The different objectives cause divergent optimal solutions. From this the authors conclude that finding a unique politically feasible and fundable solution can be very difficult, verging on impossible.

3.4 National Strategic Investments

The distributed benefits in a meshed grid, and the fact that transmission planning is mainly done on a national level has motivated research on the effect of strategic investments by national planners. This is different from studies treating the generators as strategic players (Neuhoff et al., 2005; Pozo et al., 2013; Sauma and Oren, 2006). National strategic players maximize the overall social welfare of an area, whereas generators acting as strategic players maximize the strategic generators' profit. Pozo et al. (2013) and Sauma and Oren (2006) study the generation investment response following transmission investments.

Egerer et al. (2013a) does an applied study, attempting to determine an optimal expansion plan for the European electricity grid to support the decarbonization of the electricity sector until 2050. The objective in this model is pan-European minimization of total system costs. However, as discussed previously, the benefits from transmission investments are likely to accrue to more areas than the ones bearing the costs. Thus optimal expansion plans are not likely to be implemented without some form of compensation mechanisms.

Nylund and Egerer (2013) use a non-cooperative game theoretic approach to compare bilateral cost sharing to regional cost sharing based on the proportional benefit from the investments. They use enumeration to develop a pay-off matrix. From studying this they find that the regional cost sharing solutions come closer to the system welfare optimal solutions than the bilateral cost sharing solutions. One problem with such a regional cost sharing approach is to decide on a reference point to measure the relative benefit for an area.

Two models similar to the models presented in this thesis are Bjus and Belmans (2012) and Huppmann and Egerer (2014). Bjus and Belmans (2012) compare a supranational planner to a situation where zonal planners maximize the sum of net consumer surplus, generation profit and congestion revenues less investment costs in his zone. Finally they implement a Pareto-planner which ensures that the zonal welfare does not decrease below the initial situation for any node. The zonal planner and Pareto-planner problem are modeled as MPECs. The MPEC for each node are combined to an EPEC representing the equilibrium between all planners. Bjus and Belmans (2012) use a generic algorithm to solve the MPECs, but they do not actually compute the solution to the EPEC representing the equilibrium between all planners.

Huppmann and Egerer (2014) present a three level equilibrium model with a supranational planner deciding on cross border investments on the upper level, zonal planners on the intermediate level and the spot market on the lower level. The zonal planners only decide on investments within their area. Cross border lines are decided by the supranational planner on the upper level. They use an iterative solution algorithm to identify multiple equilibria in the national strategic game between zonal planners. There may be several feasible solutions to the problem, but not all will be Nash equilibriums in the sense that a zone can have a positive deviation from the feasible solution with a different choice of strategy.

Our main contribution compared to the models above is the treatment of the planning horizon. We take a long term perspective by the inclusion of time periods. Furthermore we implement both a situation where the planning node incurs all costs associated with investments and a bilateral cost sharing situation. We also show that our MPEC can be solved to optimality for small instances.

Chapter 4

Model Formulation for the Supranational Planner

The transmission planning problem examined in this thesis has a bi-level structure. A transmission planner maximizes social welfare subject to investment constraints on the upper level, and the market outcome is decided in the lower level problem. The upper level planner's objective can be to maximize the welfare of all nodes (e.g. countries) in the market, a selection of nodes or a single node. This chapter presents a model for a planner maximizing the social welfare of *all nodes*. We call this the *supranational planner* as it maximizes the welfare on a supranational level. The purpose of this model is to represent a pan European investment perspective.

The problem structure is illustrated in Figure 4.1. This is the structure of a Stackelberg game, where the leader decides on transmission investments while anticipating the market outcome. The market constitutes the Stackelberg follower and decides on generation output, sales, flow and nodal prices. This Stackelberg game can be modeled as a mathematical program with equilibrium constraints (MPEC). When there is only one planner for all nodes, the bi-level problem can be reduced to a single level problem. This can be done because the objective function of the upper level problem and the lower level problems align, as explained in Garcés et al. (2009). The new problem structure is illustrated in Figure 4.2.

Transmission planner (LEADER):
Max {Producer surplus + Consumer surplus – Investment costs}
s.t.
Investment constraints

Market outcome (FOLLOWER):
Max {Producer surplus + Consumer surplus}
s.t.
Flow constraints
Generation constraints

Figure 4.1: Bi-level problem structure

Max {Producer surplus + Consumer surplus - Investment cost}
s.t.
Investment constraints
Flow constraints
Generation constraints

Figure 4.2: Single-level problem structure

The single level optimization problem illustrated in Figure 4.2 is much easier to solve than the bi-level MPEC illustrated in Figure 4.1. In this chapter we focus on the single level problem.

The main assumptions are discussed in Section 4.1. Section 4.2 explains the definitions used in the model. Section 4.3 describes the mathematical formulation for the single level optimization model.

4.1 Main Assumptions

Each node in the model represents a country. The nodes are connected by a set of arcs which represent power transmission lines.

The energy sources are described by their generation capacity, generation cost and capacity factor. The capacity factors are used to adjust for the seasonal availability of variable renewable energy sources, e.g. wind and solar. We do not consider uncertainty in the supply. Due to the aggregation level of the model we ignore non-convexities like minimum output levels, ramping constraints and start-up costs. We assume linear generation costs.

Demand is described by linear inverse demand curves. There are producers and consumers present in every node. All generator types are present in each node, but with different generation capacities.

The generators can sell the power they produce in their own node or to other nodes as long as there is sufficient transmission capacity on the transmission lines. The electricity prices result from market clearing in every node. We assume perfect competition in the electricity market. The focus in this thesis is not on the competition between the generators in the power market, but on the strategic investments in transmission capacity.

The transmission planner invests in transmission capacity. We assume that the transmission planner has full knowledge of the generation portfolio, its cost structure and location, as well as the demand functions in every node. The cost for transmission expansion is assumed to be a cost per unit of effect. This cost is covered by the node deciding to do the investment.

The flow of electricity in the network is modeled under the assumption of pure transportation. Each arc has an upper transmission limit. A more realistic modeling option to electricity markets is the DC load flow approach. However, given the high aggregation level of the model the pure transportation method was chosen.

The time periods can represent either a season or a year. Two seasons constitute a year.

4.2 Definitions

In both the optimization and MCP model, all indices and variables are written with small letters. Sets and parameters are written in capital letters. Dual variables are written in small Greek letters.

Sets and indices:

$n, m \in N$	Nodes
$t \in T$	Seasons
$f \in F$	Fuels

Parameters and functions:

$C^{GEN}_{n,f,t}$	Marginal production cost of fuel f in node n and season t
$CAP^{GEN}_{n,f,t}$	Maximum production capacity of fuel f in node n in season t
$AV_{n,f,t}$	Capacity factor of fuel f in node n in season t
$CAP^{T}_{n,m,t}$	Transmission capacity from node n to node m in season t
$C^{INV}_{n,m}$	Investment cost on connection between node n and m in season t
$A_{n,t}$	Demand intercept in node n in season t
$B_{n,t}$	Demand slope in node n season t

Variables:

w	Social welfare of market
$d_{n,t}$	Demand in node n in season t
$q^{prod}_{n,f,t}$	Quantity generated by power generator of type f in node n in season t
$q^{sold}_{n,m,t}$	Quantity sold by power generators in node n to node m in season t
$x_{n,m}$	Amount invested on line from node n to node m
$flow_{n,m,t}$	Flow from node n to node m in season t
$\gamma_{n,f,t}$	Lagrangian multiplier associated with generation capacity in of fuel f in node n in season t
$\phi_{n,t}$	Lagrangian multiplier associated with generation equals to sold constraint in node n in season t
$p^{t}_{n,m,t}$	Lagrangian multiplier associated with flow on line between node n to node m in season t
$\epsilon_{n,m,t}$	Lagrangian multiplier associated with flow capacity on line between node n to m in season t
$\mu_{n,m,t}$	Lagrangian multiplier associated with investment constraint on connection from n to m in season t
$p^{el}_{n,t}$	Price of electricity in node n in season t

4.3 Mathematical Model for the Supranational Planner

The model presented in this section maximize social welfare for an energy market subject to production and transmission constraints.

$$max \quad w = \sum_{n,t}(A_{n,t} \cdot d_{n,t} - 0.5 \cdot B_{n,t} \cdot d^2_{n,t}) - \sum_{n,f,t} C^{GEN}_{n,f,t} \cdot q^{prod}_{n,f,t} - \sum_{n,m} \left(C^{INV}_{n,m} \cdot x_{n,m}\right) \tag{4.1}$$

s.t

$$q^{prod}_{n,f,t} \leq CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \qquad \forall \; n,f,t \;\; (\gamma_{n,f,t}) \tag{4.2}$$

$$\sum_f q^{prod}_{n,f,t} = \sum_m q^{sold}_{n,m,t} \qquad \forall \; n,t \;\; (\phi_{n,t}) \tag{4.3}$$

$$flow_{n,m,t} \quad = \quad q^{sold}_{n,m,t} \qquad \forall \;\; n,m,t \;\; (p^{t}_{n,m,t}) \tag{4.4}$$

$$flow_{n,m,t} + flow_{m,n,t} - CAP^{T}_{n,m,t} - x_{n,m,t} - x_{m,n,t} \;\; \leq \;\; 0 \qquad \forall \;\; n,m,t \;\; (\epsilon_{n,m}) \tag{4.5}$$

$$d_{n,t} = \sum_{m} q^{SOLD}_{n,m,t} \;\; \forall \;\; n,t \;\; (p^{el}_{n,t}) \tag{4.6}$$

Equation 4.1 maximizes social welfare. Social welfare is calculated as the sum of consumer and producer surplus minus investment costs. Consumer surplus is calculated as the difference between the maximum price a consumer is willing to pay and the amount it actually pays. Producer surplus is calculated as the income from sales minus production costs. Equations 4.2 set the maximum generation capacity per time period. The parameter $AV_{n,f,t}$ accounts for variations in available generation capacity for wind and solar-based technologies. Balance between the amount of electricity generated and sold is ensured by equations 4.3. Equations 4.4 determine the flow of electricity on a transmission line. Equations 4.5 limits the total flow on a line to the maximum transmission capacity plus investments made in both directions. Investments in both directions are added to this equation to ensure that an investment made in direction from node n to m, also increase the transmission capacity from node m to node n. Equations 4.6 are the market clearings.

Chapter 5

Model Formulation for the Zonal Planner

This chapter presents the bi-level model which represents investment decisions from a zonal planner's perspective. The zonal planner's objective is to maximize the social welfare in one zone or node. The problem structure is the same as in the previous chapter, but here the objective functions of the upper and lower level do not align. Thus the bi-level problem cannot be reduced to a single level problem, and we have to solve a mathematical problem constrained by an optimization problem. The main assumptions are the same as in the previous chapter, but the upper level planner now has the objective of maximizing the social welfare in his node. The upper level planner decides on investments in transmission capacity on lines connected to his node.

The assumptions for this model is given in Section 5.1. Section 5.2 explains the mathematical notation used in the zonal planner model. The mathematical formulation is given in Section 5.3. We also implement a bilateral cost sharing approach. This is explained in Section 5.4 and the complete mathematical formulation is presented in Appendix B. Section 5.5 describe the decomposition of the models using the disjunctive constraints approach. The complete formulations is presented in Appendix A.

5.1 Main Assumptions

The main assumptions for the zonal planner model are the same as those in Section 4.1 in Chapter 4.

5.2 Definitions

As in section 4.2, all indices and variables in the following mathematical formulation are written with small letters. Sets and parameters are written in capital letters, while dual variables are written in small Greek letters.

Sets and indices:

$n, m \in N$	Nodes
$n \in N_l$	Leader nodes
$t \in T$	Seasons
$f \in F$	Fuels

Parameters and functions:

$C^{GEN}_{n,f,t}$	Marginal production cost of fuel f in node n and season t
$CAP^{GEN}_{n,f,t}$	Maximum production capacity of fuel f in node n in season t
$CAP^{INV}_{n,m}$	Maximum investment level on line from node n to m
$AV_{n,f,t}$	Capacity factor of fuel f in node n in season t
$CAP^{T}_{n,m,t}$	Transmission capacity from node n to node m in season t
$C^{INV}_{n,m}$	Investment cost on connection between node n and m in season t
$A_{n,t}$	Demand intercept in node n in season t
$B_{n,t}$	Demand slope in node n season t
K^{1a},K^{1b},K^{2a},K^{2b} K^{3a},K^{3b},K^{4a},K^{4b} K^{5a},K^{5b},K^{6a},K^{6b}	Constants for disjunctive constraints

Variables:

w	Social welfare of market
$d_{n,t}$	Demand in node n in season t
$q^{prod}_{n,f,t}$	Quantity generated by power generator of type f in node n in season t
$q^{sold}_{n,m,t}$	Quantity sold by power generators in node n to node m in season t
$x_{n,m}$	Amount invested on line from node n to node m
$flow_{n,m,t}$	Flow from node n to node m in season t
$\gamma_{n,f,t}$	Lagrangian multiplier associated with generation capacity in of fuel f in node n in season t
$\phi_{n,t}$	Lagrangian multiplier associated with generation equals sold constraint in node n in season t
$p^t_{n,m,t}$	Lagrangian multiplier associated with flow on line between node n to node m in season t
$\epsilon_{n,m,t}$	Lagrangian multiplier associated with flow capacity on line between node n to m in season t
$\mu_{n,m,t}$	Lagrangian multiplier associated with investment constraint on connection from n to m in season t
$p^{el}_{n,t}$	Price of electricity in node n in season t

Binary variables for disjunctive constraints

$r^1_{n,t}$,$r^2_{n,f,t}$, $r^3_{n,m,t}$,$r^4_{n,m,t}$, $r^5_{n,f,t}$,$r^6_{n,m,t}$, $r^7_{n,m}$	Binary variables used to replace complementarity conditions with disjuctive constraints

5.3 Mathematical Model for the Zonal Planner

In this model, the leading zone decides on capacity investments in order to maximize his own welfare subject the market outcome. The zonal planner cannot reduce the capacity on any line.

$$min \;\; w = \sum_{n \in N_l, t} (-0.5 \cdot B_{n,t} \cdot d_{n,t}^2) + \sum_{n \in N_l, f, t} C_{n,f,t}^{GEN} \cdot q_{n,f,t}^{prod} - \sum_{m,t} p_{m,t} \cdot q_{n,m,t}^{sold} - \sum_{m,t} flow_{n,m,t} \cdot p_{n,m,t}^{t} + \sum_{n,m} C_{n,m}^{INV} \cdot x_{n,m} \quad \forall m \tag{5.1}$$

s.t

$$0 \;\; \leq \;\; x_{n,m} \;\; \leq \;\; CAP_{n,m}^{INV} \quad \forall n, m \in N \tag{5.2}$$

$$0 \;\; \leq \;\; -A_{n,t} + B_{n,t} \cdot d_{n,t} + p_{n,t}^{el} \;\; \geq \;\; 0 \;\; \perp \;\; d_{n,t} \geq 0 \tag{5.3}$$

$$0 \;\; \leq \;\; C_{n,f,t}^{GEN} + \gamma_{n,f,t} + \phi_{n,t} \;\; \geq \;\; 0 \;\; \perp \;\; q_{n,f,t}^{prod} \geq 0 \tag{5.4}$$

$$0 \;\; \leq \;\; -\phi_{n,t} - p_{n,m,t}^{t} - p_{m,t}^{el} \;\; \geq \;\; 0 \;\; \perp \;\; q_{n,m,t}^{sold} \geq 0 \tag{5.5}$$

$$0 \;\; \leq \;\; \epsilon_{n,m,t} + \epsilon_{m,n,t} + p_{n,m,t}^{t} \;\; \geq \;\; 0 \;\; \perp \;\; flow_{n,m,t} \geq 0 \tag{5.6}$$

$$0 \;\; \leq \;\; -q_{n,f,t}^{prod} + CAP_{n,f,t}^{GEN} \cdot AV_{n,f,t} \;\; \geq \;\; 0 \;\; \perp \;\; \gamma_{n,f,t} \geq 0 \tag{5.7}$$

$$\sum_{f} q_{n,f,t}^{prod} - \sum_{m} q_{n,m,t}^{sold} = 0 \;\; \perp \;\; \phi_{n,t} \;\; free \tag{5.8}$$

$$flow_{n,m,t} = q_{n,m}^{sold} \;\; \perp \;\; p_{n,m}^{t} \;\; free \tag{5.9}$$

$$0 \;\; \leq \;\; -flow_{n,m,t} - flow_{m,n,t} + CAP_{n,m,t}^{T} + x_{n,m} + x_{m,n} \;\; \geq \;\; 0 \;\; \perp \;\; \epsilon_{n,m,t} \geq 0 \tag{5.10}$$

$$d_n = \sum_{m} q_{n,m,t}^{sold} \;\; \perp \;\; p_n^{el} \;\; free \tag{5.11}$$

Equation 5.1 is the objective function of the zonal planner. It consists of the sum of the consumer and producer surplus minus transmission and investment costs.

The objective function is non-linear and non convex due to two bi-linear terms including dual variables, $p_{m,t} \cdot q^{sold}_{n,m,t}$ and $flow_{n,m,t} \cdot p^t_{n,m,t}$. Equations 5.3 - 5.11 are the KKT conditions of the lower level problem. These are found using the procedure described in Section 2.4.1. The lower level is maximizing the welfare in the market.

5.4 Bilateral Cost Sharing

The model described in the Section above, 5.3, assumes that all investment costs are covered by the leader zone. An alternative is to introduce bilateral cost sharing. We implement this by letting the nodes on either side of an upgraded line share the costs equally. We also let the leader node invest only on the lines it is directly connected to instead of all nodes as in the formulation above. The lower level are allowed to invest on the other lines. We implement these changes by letting the leader node pay half the cost of investments, adding a complementarity condition with respect to the investment variable $x_{n,m}$ to the lower level and adding a constraint specifying which lines the upper and lower level can invest on.

The leader's new objective function becomes:

$$\begin{aligned} min \;\; w = \sum_{n \in N_l, t} (-0.5 \cdot B_{n,t} \cdot d^2_{n,t}) \\ + \sum_{n \in N_l, f, t} C^{GEN}_{n,f,t} \cdot q^{prod}_{n,f,t} - \sum_{m,t} p_{m,t} \cdot q^{sold}_{n,m} \\ - \sum_{m,t} flow_{n,m,t} \cdot p^t_{n,m,t} + \sum_{n,m} \left(0.5 \cdot C^{INV}_{n,m} \cdot x_{n,m}\right) \quad \forall m \end{aligned} \tag{5.12}$$

s.t.

$$0 \;\; \leq \;\; x_{n,m} \;\; \leq \;\; CAP^{INV}_{n,m} \quad \forall n \in N_l \tag{5.13}$$

The additional complementarity condition with respect to the investment variable $x_{n,m}$ becomes:

$$0 \;\; \leq \;\; 0.5 \cdot C^{INV}_{n,m} - \sum_t (\epsilon_{n,m,t} + \epsilon_{m,n,t}) \;\; \geq \;\; 0 \;\; \perp \;\; x_{n,m} \geq 0 \;\; \forall \;\; n, m \neq N_l \tag{5.14}$$

In equation 5.12, we see that the leader only covers half of the investment costs. The remaining parts of the lower level problem are not changed. The full formulation for the zonal transmission planner problem with bilateral cost sharing is given in Appendix B.

5.5 Decomposition of the MPEC using Disjunctive Constraints

The lower level problem can be reformulated as a mixed integer non-linear problem (MINLP) by expressing the complementarity conditions (5.3 - 5.11) in disjunctive form. We will illustrate this approach using the KKT-condition for demand.

$$0 \leq -A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \geq 0 \perp d_{n,t} \geq 0 \tag{5.15}$$

Rewritten using disjunctive constraints this complementarity condition becomes:

$$-A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \geq 0 \tag{5.16}$$

$$-A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \leq K^{1a} \cdot r^{1}_{n,t} \tag{5.17}$$

$$d_{n,t} - K^{1b} \cdot \left(1 - r^{1}_{n,t}\right) \leq 0 \tag{5.18}$$

$r^{1}_{n,t}$ is a binary variable and K^{1a} and K^{1b} are problem specific parameters. This approach is used on all complementarity conditions in the lower level problem. The full mathematical formulation for the models using the disjunctive constraints approach can be found in Appendix A.

Chapter 6

Data Set

The following chapter describes the data set we have used when running the models described in Chapters 4 and 5. We have chosen to represent Germany, Denmark, the Netherlands, Norway, Sweden and the United Kingdom with each country as one node. We chose these countries based on the strategic connections between them, and their generation mixes. These are also most of the countries comprised in the North and Baltic Seas grid infrastructure project which is the number one of "European infrastructure projects for 2020 and beyond" (European Comission, 2010b). Norway and Sweden are rich in hydro power and benefit from being connected to the thermal dominated European system. Furthermore Germany and Denmark have a large share of wind power in their generation mix, and the UK is planning to expand their wind power production capacity. Furthermore Germany has a significant share of solar power. The Netherlands is of strategic importance due to the sub sea cables to Norway and the UK as well as the proximity to the German market.

The model has a long-term perspective and we use the data set to simulate a system state of “today” and the year 2020. The “today” situation is represented by data for 2011 as this was the latest year we were able to obtain comprehensive generation capacity data for. Both years are divided into two seasons, winter and summer.

6.1 Transmission Capacity

Figure 6.1 illustrates the network represented in the model. The grey lines represent existing interconnectors with no planned upgrades, the red lines represent interconnectors where upgrades are planned and the dashed lines represent possible future interconnectors. The existing transmission capacities are based on net transfer capacities obtained from Entsoe (Entsoe, 2014a,b). Some interconnectors does not have the same transmission capacity in both directions.[1] In those cases we have used the lowest transmission capacity to represent the interconnection. We used the Enstoe Ten Year plan for 2020 (Entsoe, 2014c) to find transmission capacities for 2020. Table 6.1 gives an overview of new and existing transmission capacity between the countries represented in the model. There is a possible new line planned between Denmark and the United Kingdom, but the capacity of this is not decided [2].

Based on a report from Thema Consulting Group (2012) we have set the price for transmission expansion to 1.7 €/MW.

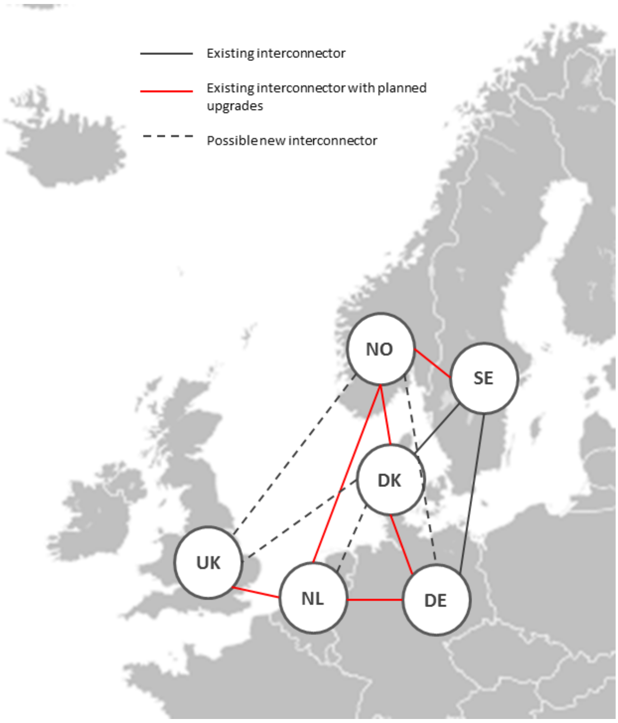

Figure 6.1: Map of cross border interconnectors in Europe

[1] The transmission capacity also depends on the capacity in the grid on either side of the interconnector.

[2] http://www.energinet.dk/EN/El/Nyheder/Sider/Energinet-dk-og-National-Grid-underskriver-aftale-om-Englandskabel.aspx

Connection	Current capacity	Planned upgrades	Project name
NO - SE	3595	1320	South West Link
NO - DK	1000	700	Skagerak 4
NO - NL	700	700	NordNed 2
NO - DE	0	1400	Nord.Link
NO - UK	0	1400	NorthConnect
SE - DK	2040	-	-
SE - DE	615	-	-
DK - DE	2100	500	-
DK - NL	0	700	COBRAcable
DK - UK	0	?	Possible new line
DE - NL	3850	1000- 2000	-
NL - UK	1000	1000	Nemo.Link

Table 6.1: Cross-border transmission capacities [MW] between the countries represented in the model

6.2 Generation Capacity

The generation capacities were taken from IEAs International Energy Statistics database (The International Energy Agency (IEA), 2014). We chose to disregard geothermal, wave, tidal and pumped storage in the dataset due to the small installed capacities. Moreover, four additional fuels would increase the number of variables in the model. Thus we had to compromise between accuracy and computational time. We used data from European Environmental Agency (EEA) to divide the fossil fuel capacity in coal and lignite, oil and natural gas respectively. Figure 6.2 gives an overview of the generation capacities in each country in GW. The fuels included are natural gas oil, coal, biamass, wind, solar and hydro power. The 2020 generation capacities are based on trends presented by European Comission (EC) (2009), Eurelectric (2011) and Eurelectric (2012), as well as Jaehnert and Doorman (2014). Figure 6.3 gives an overview of the 2020 generation capacities in GW. All countries increase their generation capacity, and the share of natural gas and renewable sources increases in 2020.

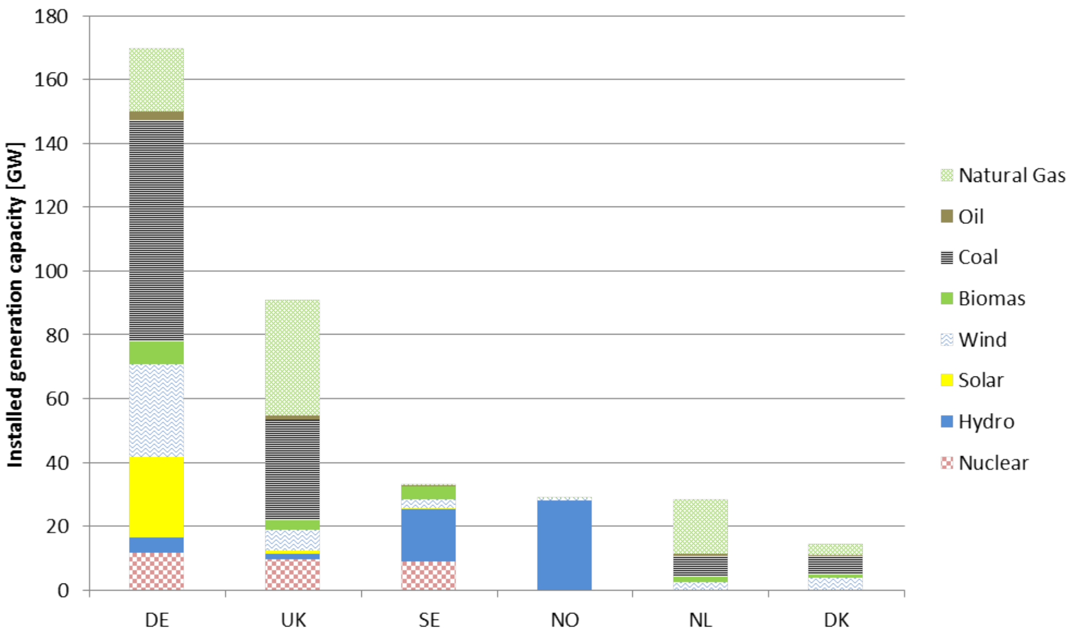

Figure 6.2: Installed generation capacity in GW in the year 2010

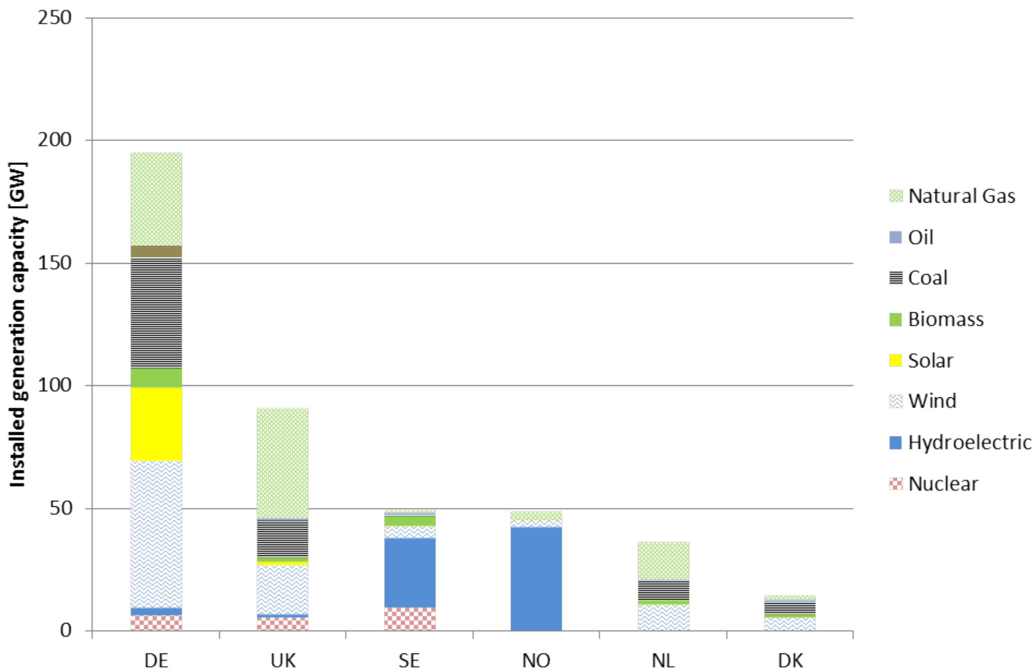

Figure 6.3: Installed generation capacity in GW in the year 2020

The wind and solar capacities are adjusted for weather conditions with a capacity factor. In general there is more wind in the winter and more sun in the summer. To represent this variability we use one summer capacity factor and one winter capacity factor for each energy source. The capacity factor for wind is based on Sinden (2007), who did and analysis of the wind power resource of the United Kingdom. The capacity factors for solar power were calculated based on data form the EEX transparency platform[3]. We found the solar power production for the 12th of each month for 12 succeeding months in 2012 and 2013. We let October to March represent winter and April to September represent summer. First the average availability for each day was calculated, assuming the total installed capacity to be 25 094 MW. Next, these days were assumed to represent the average for a month. Consequently the winter capacity factor is the average of the capacity factors in the winter months and the summer capacity factor is the average of the capacity factors in the summer months. The resulting capacity factors are represented in Table 6.2. We assume a capacity factor of 1 for the other technologies.

	Summer	**Winter**
Wind	20.0 %	38.7%
Sun	20.2 %	3.9%

Table 6.2: Capacity factors of wind and solar energy

6.3 Marginal Costs

The marginal costs for the different technologies are based on Doorman and Frøystad (2013). They present marginal costs for coal and lignite separately, however we have aggregated coal and lignite in one category as this saves one fuel and thus decreases the number of variables in the model. Furthermore Germany is the only country in the model with a significant share of lignite in their energy mix. We assume 20% of the aggregated coal and lignite generation capacity to be lignite plants and use a weighted average to calculate the marginal cost used in our data set. Table 6.3 gives an overview of the marginal costs used in the model. We assume the marginal production costs for wind and solar power to be zero adn the marginal costs for hydroelectric power to be similar to the water value, which is the value of one extra unit of water in the reservoir. As the Norwegian power system is dominated by hydro power the electricity price will be close to the water value. The average spot price in the NO1 area in Norway in the years 2010 to 2013 is 42 €/MWh. Based on this we use 40 €/MWh as the marginal cost for hydro power in the data set.

[3]http://www.transparency.eex.com/en/

Technology	Marginal cost
Coal	36
Natural gas in UK	37.5
Natural gas other	61
Oil	150
Nuclear	9.5
Hydro	40
Wind	0
Solar	0
Biomass	29

Table 6.3: Marginal production costs [€/MWh] for various technologies

6.4 Electricity Demand

Demand is represented by linear, inverse demand curves for each country and each season. We have used the method for calculating the inverse demand curve described in Leuthold et al. (2012). The reference demand for each country is found in data provided by ENTSO-E. We assume a reference price of 60 €/MWh for the winter and 40 €/MWh for the summer. These prices are based on The Eurpean Comission Quarterly Report on European Electricity Markets for the third and fourth quarter in 2012 (European Comission, 2012). The electricity market is a very inelastic market. Not all consumers observe the spot market price and thus cannot react to it. This means that large price changes will not cause large changes in demand. Lijesen (2007) does a study of the Netherlands and finds a price elasticity of $-$ 0.0014 with a linear specification and of -0.0043 using a loglinear specification. However, several studies cited in Lijesen (2007) find higher elasticity. We have assumed an elasticity of -0.1, which is the same as the one used in Egerer et al. (2013b).

Based on projections from Eurelectric (2013) and Bye et al. (1995) we have assumed an increase in demand in all countries except Germany and United Kingdom. The estimated annual growth rate in demand is presented in Table 6.4.

Country	Growth Rate
Norway	0.40 %
Sweden	0.13 %
Denmark	061 %
Germany	-1.08 %
Netherlands	0.83 %
United Kingdom	-0.91 %

Table 6.4: Annual growth rate in demand from 2010 until 2020.

6.5 Data Quality

We believe our dataset is realistic and that it has a sufficient level of detail given the high aggregation level of our model. We will however discuss some potential weaknesses here. The transmission capacity data is good; but they could be improved by including different transmission capacities in different directions where this occurs. The generation capacities are based on data from IEA, and we assume these to be accurate. However we have used data from 2005 to divide the fossil fuel generation capacity into shares of coal, oil and natural gas for each country. We have reason to believe that these shares have changed somewhat since 2005, but this was the latest data obtainable. On the one hand we could assume the share of coal and oil to have decreased due to the high carbon emissions from these sources. Furthermore the price of oil is very high compared to coal and gas and there is an overall trend towards decreasing share of oil in the energy mix. On the other hand, the price of coal is low compared to natural gas resulting in an increasing share of coal.

The 2020 generation capacities are only projections. The capacities are not meant to represent a “most likely” scenario for European power generation capacities in 2020, but rather a future with large amounts of wind and solar power in the energy mix to see how more variable generation capacity affects the need for transmission capacity.

The calculation of the solar power capacity factors is based on 12 different days. Nothing indicates that any of these days are outliers. The resulting capacity factors are along the lines of what is to be expected for Germany. When we divide the year into summer and winter we get a low capacity factor in the winter and a high capacity factor in the summer and an annual capacity factor of about 12%. We assume that these capacity factors are representative for all countries in the model, thus we assume they have similar insolation. IEA presents capacity factors for different utility scale generators in the US. These are higher than the capacity factors we have calculated based on data for Germany, however the average insolation in Germany is lower than the US. Thus we decided to use the capacity factors based on the EEX transparency platform.

The wind capacity factors are based on a study (Sinden, 2007) conducted for onshore installations in the UK. Due to lack of data we assume these capacity factors are representative for all countries represented in the model. With increasing offshore installations the capacity factor for wind is likely to increase, but this is not reflected in our data set.

Because we assume the same capacity factors for sun and wind for all countries represented in the model we loose some dynamics. Denmark can have high wind production when the UK does not and the other way around. The sun may not shine at the same time and as much in Sweden as in Germany. However the representation of this kind of dynamics would be more important if we had a finer time resolution. Then we could model situations where transmission capacity is needed one way one day and the other way the next.

The marginal production costs vary in different papers. This is not public information. Thus it has to be calculated based on assumptions of among others, efficiency, emissions and operation hours of different plant types. We checked the prices presented in Doorman and Frøystad (2013) using their fuel prices, a carbon price of 14 €/MWh and the method presented in Traber and Kemfert (2011). Using this method we got slightly higher costs for natural gas and lower costs for oil than the costs presented in Doorman and Frøystad (2013). As the marginal costs in Doorman and Frøystad (2013) were more similar to the costs presented in other papers, we decided to use these costs in the model. In reality the marginal production cost is dependent on plant type, not just fuel, but this is not reflected in our model. We do however believe the level of detail is sufficient given the aggregation level of the model.

We assume the real costs will stay the same in 2020. Improved technologies would decrease the costs, but increased fuel and carbon prices would increase the costs. Fuel costs could increase due to increased demand from emerging markets and are thus dependent on the world economy. The carbon price will increase if EU succeeds in revitalizing the EU ETS market, or agree on other renewable policies to increase the cost of emitting CO_2. It is however worth noting that neither Exxon[4], nor Statoil[5] deem such a scenario particularly likely when reporting on climate change risk and strategies for climate change.

When calculating the linear, inverse demand curves we assume the same reference price for all countries. This is not quite accurate as there are some electricity price differences between European countries.

[4]http://corporate.exxonmobil.com/en/environment/climate-change/managing-climate-change-risks/carbon-asset-risk

[5]lhttp://www.statoil.com/en/NewsAndMedia/News/Downloads/Statoil%20response %20to%20Ceres%20letter%209%20October%202013.pdf

Chapter 7

Implementation

This chapter presents important aspects of the implementation of the models presented in Chapters 4 and 5. Section 7.1 describes GAMS and the solvers used to run the models. 7.2 describes how the Ks are chosen. Hardware specifications are given in Section 7.3.

7.1 Software

The implementation of the models from chapter 4 and 5 was done using the The General Algebraic Modeling System (GAMS) IDE version 24.1.3. GAMS is "a high level modeling language for the compact representation of large and complex models" (Rosenthal, 2013). The software allows model representations to be independent of solution algorithm and accommodates solving of mixed complementarity problems as well as linear, nonlinear, mixed integer and mixed integer nonlinear optimization problems. A detailed introduction to the GAMS language and syntax can be found in Rosenthal (2013).

GAMS does not directly solve the problem, but uses a solver chosen by the user. The model in Chapter 4 is a quadratic optimization problem which we solve using a NLP solver. As the CONOPT solver proved to solve our problem efficiently, we chose to use this solver. The model in chapter 5 is reformulated as an MINLP. The model has a non-convex objective function and therefore require a global solver such as BARON.

CONOPT, developed by Arne Drud, is an nonlinear programming (NLP) algorithm which finds local optima (Drud (2013)). For convex models CONOPT will find the global solution. The solver is built for non-linear, large and sparse models. CONOPT has considerable build-in logic which selects the solution approach that seems most suited given information from the model. The approach is adjusted dynamically as new information about the model is revealed. Models solve more easily with CONOPT if initial values are provided. Also, good bounds on variables and proper scaling will ease the solution process.

Developed by Nick Sahinidis, the Branch-And-Reduce Optimization Navigator (BARON) solver is guaranteed to find a global solution of nonlinear (NLPs) and mixed-integer nonlinear programs (MINLP) (Sahinidis (2013)). The algorithm consists of two parts; the reduce and the branch part. The reduce part of the solver's algorithm combines constraints progagation, interval analysis, and duality. The algorithm's branch part utilizes advanced branch-and-bound optimization concepts. The solver requires all variables to have finite bounds. If not provided by the modeler, BARON will set upper and lower bound to variables using the model constraints.

7.2 Choosing the Values for the Disjunctive Constraint Parameters

As mentioned in section 2.4.4, choosing good values of the Ks in the disjunctive constraints approach is important and challenging. No general procedure for choosing good Ks exist, as the values of the Ks are problem specific.

The Ks should be as small as possible, yet still so big that optimal solutions are not cut out of the feasible region of the model. If the Ks are too big, the mix between large and small model parameters may cause solver calculation errors. GAMS solvers find it challenging to run models where parameters have very different magnitude. For example, given a minimization problem, the GAMS solvers may experience finding decreased objective value after adding integer cuts. This does not make sense as integer cuts worsen the objective function value. The reason for these calculation errors is that if the solver encounters big and small parameters, the solver might choose to round the small numbers to zero. This happened in the example above, where the result was wrongly calculated search directions. Proper scaling of the model can help avoiding this problem.

The best way to find good Ks is to use information from the model data. Finding good bounds on primal variables is rather straightforward as they usually relate to physical amounts with known upper limit. The challenge is to set good bound on the dual variables. It might be rewarding to think of the duals as shadow prices, i.e marginal costs of one more unit. This may give an idea of the value of the dual. Also, solving a small instance of the model can give additional insights in what level the duals will take.

7.3 Hardware

The models have been run on an HP desktop computer using Windows 7. It has an Intel Core i7 CPU with 16 GB RAM running at 3.4 HZ.

We could not find a feasible solution to the largest instance of the zonal transmission planner model in 24 hours. A faster processor would solve more nodes in the branch-and-bound tree in the same time, and therefore maybe bring the solution time down. For the same reason, solving the branch-and-bound tree using parallel runs could also increase the chances of finding feasible solutions. However, we cannot say this for sure as we do not know how far away the solver is from the feasible solution.

Chapter 8

Computational Results and Analysis

This chapter summarizes results from test instances of the models presented in Chapter 4 and 5. We start by presenting preliminary results in Section 8.1. Section 8.2 reports on the market outcome with the initial transmission capacity. This is compared to the results from the supranational planner and the zonal planner. For the zonal planner we consider both no cost sharing and bilateral cost sharing. We illustrate the conflicting objectives and the effect of cost sharing by comparing the outcomes for the different planners.

The effect of the long term planning horizon is illustrated by comparing the solution for supranational planner planning for one year and a supranational planner planning for two years.

As we discuss in Section 8.1 we are only able to solve the model for the zonal planner for small instances, thus we use an aggregated version of the data set presented in Chapter 6 to analyze the outcomes for the different planners. In the reduced data set we omit Sweden and aggregate Germany and the Netherlands to "DENE". We also aggregate all thermal capacity, including biomass and nuclear, to one generation type and include only two time periods.

Finally we perform a sensitivity analysis with focus on how different demand and generation input parameters influence the solution.

8.1 Preliminary Testing

In this section we report on the solution times for the various models, and show that the upper and lower bounds of the zonal planner model converge.

The number of continuous and binary variables, running time and final solution gap is presented in Table 8.1. The supranational transmission planner models used the CONOPT solver. The zonal transmission planner models were solved using BARON.

	Time periods	Nodes	Fuels	Variables	Binary Variables	Solution time	Relative gap
No Investment	2	4	4	121	0	0	0
Supranational planner	2	4	4	121	0	0	0
Norway as zonal planner, no cost sharing	2	4	4	401	168	02:23:00	0.009
Norway as zonal planner, bilateral cost sharing	2	4	4	417	178	00:00:10	0.00337
Norway as zonal planner, no cost sharing	4	4	4	785	336	> 24:00:00	-
Supranational planner	4	4	4	225	0	0	0
Supranational planner	4	6	8	469	0	0	0

Table 8.1: Solution report for all models

As can be see from Table 8.1 that we were not able to solve the zonal transmission planner model for the biggest data set. Therefore, we solve the models for a reduced data set which contains four nodes, four fuels and two time periods. The nodes are Norway, Denmark, DENE and the UK. The DENE is an aggregation of the data for Germany and the Netherlands. Demand of this zone is set to Germany's as reference consumption for this zone is substantially larger than Netherlands'.

The seasonal data is aggregated in order to represent the years 2010 and 2020. Thus, we represent single years instead of years with two seasons. We also reduce the amount of fuels in the market from eight to four. Generation capacity for oil, gas, coal, nuclear and biomass are aggregated into the fuel type "Thermal". The generation cost of this fuel is the weighted average of generation costs with respect to capacity, meaning we multiply the cost of generation with the share of generation for all generation types.

In terms of convergence for the MPEC we see from Figure 8.1 that the upper and lower bounds converge. When we set Norway as leader in the MPEC we saw that BARON found many feasible solutions throughout the solution time as illustrated in Figure 8.1. This is not uncommon for non convex problems as discussed in section 2.5

For the zonal planner we saw that BARON reported the first solution that met the relative optimality criteria. Due to our familiarity with the model we could conclude that the reported solution was not the global optimum. Thus, the relative optimality criteria was changed from the default setting at 0.1 to 0.0009 in order to minimize the risk of reporting a local solution rather than the globally optimal solution.

In general the solver finds more feasible solutions to models making transmission investments than to models not investing. For the zonal planner and DENE as leader the model found a feasible solution early and spent most of the running time on proving optimality.

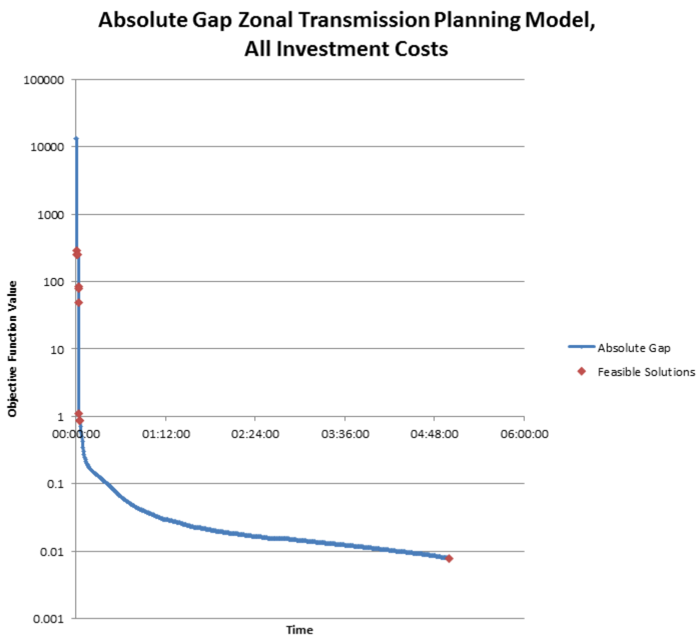

Figure 8.1: Absolute gap for two time periods zonal transmission model all costs model given Norway as leader. Logarithmic vertical axis.

8.2 Supranational Transmission Planning Model

In this section we report on the solutions from two instances of the supranational transmission planning model.

8.2.1 Initial Market Outcome

Here we present the results from supranational transmission planning with investment decisions fixed to zero. This solution will function as a benchmark for the other results. Market outcome data are presented in Table 8.2 and the transmission capacities are displayed in Figure 8.2. Grey boxes show the initial transmission capacities.

	Norway		Denmark		DENE		United Kingdom	
	2011	2020	2011	2020	2011	2020	2011	2020
Generation	17.129	17.376	2.251	2.496	67.505	58.984	38.357	37.714
Demand	15.429	15.676	4.331	4.513	67.125	58.667	38.357	37.714
Price	0.043	0.047	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.343		2.354		33.511		20.255	
PS	0.061		0.127		1.812		0.413	
CS + PS	8.404		2.481		35.323		20.668	
Investments	0							
Investment Cost	0							
Social Welfare	66.863							

Table 8.2: Market outcome for supranational planner with investments fixed to zero. Generation and demand is given in GW. Prices are given in €/GWh.

From Table 8.2 we see that generation and demand levels increase slightly in both time periods for Norway and Denmark. In DENE and the UK, generation and demand decrease in 2020. This correspond to the input data used in the model. Prices are equal to the marginal cost of the last generation technology to enter the production mix, this is known as merit order [1] In all zones consumer surplus is considerably greater than producer surplus. This is to be expected as the only profitable generators are those based on hydro and renewable generation because these are the only fuel types with marginal cost below the electricity price. Most zones have a very low generation capacity of these fuels. This results in small producer profits. All lines out of Norway are used at full capacity, i.e they are congested.

Norway experiences limited export possibilities, as the lines connecting Norway and the other countries are congested. Thus, Norway is not able to utilize its full generation capacity. Norway has a large quantity of hydro generation capacity, which has a marginal cost lower than the electricity price in the other zones. If Norway's export capacity ws higher, producer surplus would increase. In turn this would increase social welfare. Thus, Norway seems to have a potential to increase social welfare by transmission investments.

[1] Merit order is a way of organizing the available sources for electricity generation in ascending order of their marginal production costs. The sources with the lowest marginal costs will be included in the energy mix first.

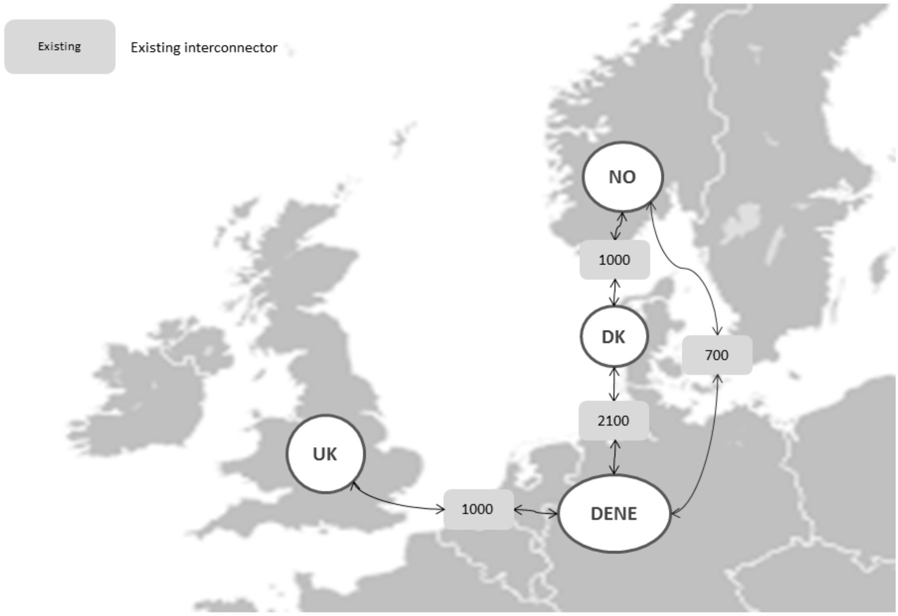

Figure 8.2: Map showing initial transmission grid

8.2.2 The Supranational Transmission Planner

Here we report on the results from the supranational transmission planner making investment decisions. Market outcome data are presented in Table 8.3 and the transmission investments are displayed in Figure 8.3. In the Figure, red boxes indicate new transmission lines, while blue boxes show lines that have been upgraded. The upper number in the red and blue boxes show the initial transmission capacity. The lower number show how much the line is upgraded. The sum of the upper and lower number give the total new transmission capacity.

In Table 8.3 we see that zonal generation vary more between time periods than in the benchmark case. In Norway generation is higher in 2020 than in 2010. In Denmark generation stays almost the same in both time periods. In DENE and the UK, we see that generation decrease in 2020. Demand increase slightly in 2020 for Norway and Denmark, while it decreases for DENE. Again, this is to be expected because of the data used in the model. In 2010, electricity prices are the same throughout the market. In 2020, the price in Norway is slightly lower than in the rest of the market. As Figure 8.3 show, a new line is built between Norway and the UK. Upgrades are done on the lines connecting Norway and Denmark. The two upgraded lines and the line between Norway and DENE are used at full capacity in 2020.

	Norway		Denmark		DENE		United Kingdom	
	2011	2020	2011	2020	2011	2020	2011	2020
Generation	28.524	42.884	1.234	1.479	66.488	57.967	28.91	14.144
Demand	15.343	15.579	4.331	4.513	67.125	58.667	38.357	37.714
Price	0.043	0.05	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.246		2.354		33.511		20.255	
PS	0.321		0.127		1.812		0.413	
CS + PS	8.567		2.481		35.323		20.668	
Investments	25.604							
Investment Cost	0.044							
Social Welfare	66.994							

Table 8.3: Market outcome for the supranational planner. Generation and demand is given in GW. Prices are given in €/GWh.

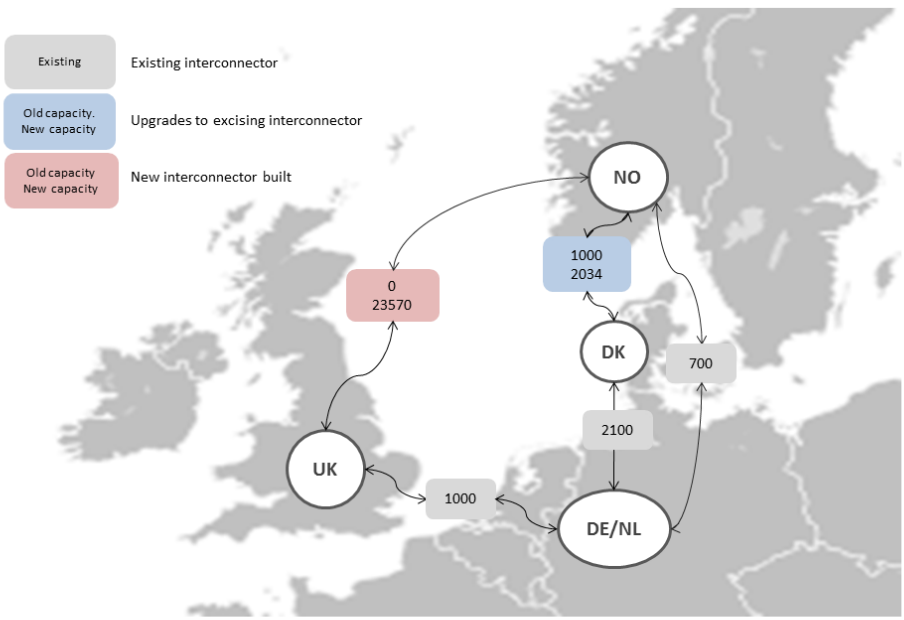

Figure 8.3: Map showing the supranational planning investment decision

Compared to the no investment situation, we see that market social welfare increase in the supranational planning model. In order to achieve optimal welfare, the planner will dispatch the cheapest generation first. Thus, the planner will dispatch hydro power before introducing thermal energy in the production mix, as hydro power is cheaper than thermal generation. We see that Norway produces more in both 2010 and 2020 when transmission investments are made. In 2020, installed hydro power generation capacity in Norway has increased. We see that this increased capacity is only utilized when transmission investments are made. Consequently, investments are made so the supranational planner can dispatch all of Norway's cheap hydro power capacity to countries that have a large share of thermal generation capacity such as the UK and DENE. This explains UK's decreased generation in 2020. The raise in generation in Norway has a positive impact on the zone's producer surplus. As demand in Norway falls because of higher electricity prices, compared to the no investment case, Norway's consumer surplus decrease. However, the increased producer surplus is high enough to cause a net increase in Norway's social welfare. The other zones in the market experience no change in producer and consumer surplus. This seems reasonable as they did not experience congested transmission lines in the initial market outcome. Even though the UK generate less in 2020 compared to the no investment case, it still achieves the same level of producer surplus as less of the expensive thermal generation is used. Thus, as a consequence of Norway's increased social welfare the total social welfare of the market increases compared to the initial market outcome.

8.3 Zonal Transmission Planner

In this section we present the results from various zonal transmission planners. We first look at the situation where the zonal planner incurs all the investment cost and then we look at the effect of bilateral cost sharing.

8.3.1 Norway as Zonal Transmission Planner and No Cost Sharing

In this section we present the results from letting Norway be the zonal transmission planner covering all investment costs model. Market outcome data are presented in Table 8.4 and the transmission investments are displayed in Figure 8.4.

	Norway		Denmark		DENE		United Kingdom	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.524	42.884	3.231	1.479	68.225	61.001	25.176	11.060
Demand	15.343	15.529	4.331	4.513	67.125	58.667	38.357	37.714
Price	0.043	0.052	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.219		2.354		31.511		20.255	
PS	0.348		0.126		1.812		0.413	
CS + PS	8.567		2.480		35.323		20.668	
CS + PS - INV	8.523		2.480		35.323		20.668	
Investment Cost	0.044							
Total Social Welfare	66.994							
Investments	25.655							

Table 8.4: Market outcome for the zonal planner covering all costs. Norway is leader. Generation and demand is given in GW. Prices are given in €/GWh.

When Norway decides on all investments in the market the market outcome is very similar to the outcome from the supranational transmission planner.

From Table 8.4 we see that the resulting generation is the same in Norway and Denmark for this planner as for the supranational model. In DENE, generation is higher in this situation than the resulting generation from the supranational planner in both years. In the UK, generation is lower for the supranational model than the resulting generation for this planner. Demand in Norway is higher in 2020 than in 2010, but compared to the supranational model, demand is lower in 2020 when we look at the results from the zonal planner. Demand in the other zones is the same. The reduced demand in Norway is due to a slightly higher price for the zonal planner than for the supranational planner. Consumer surplus is lower and producer surplus is higher in Norway, however the sum of these is the same as in the supranational case. Consumer and producer surplus remain the same as the supranational case for all other zones. The zonal planner investment in a new line between Norway and the UK and upgrades the lines between Norway and DENE Norway and Denmark and DENE and UK. We see that investments are done on the same lines as when we considered the supranational planner. In 2010, the lines between Norway and Denmark, DENE and Denmark, and the UK and DENE are congested. In 2020, the lines between Norway and DENE, Norway and the UK and DENE and the UK are congested.

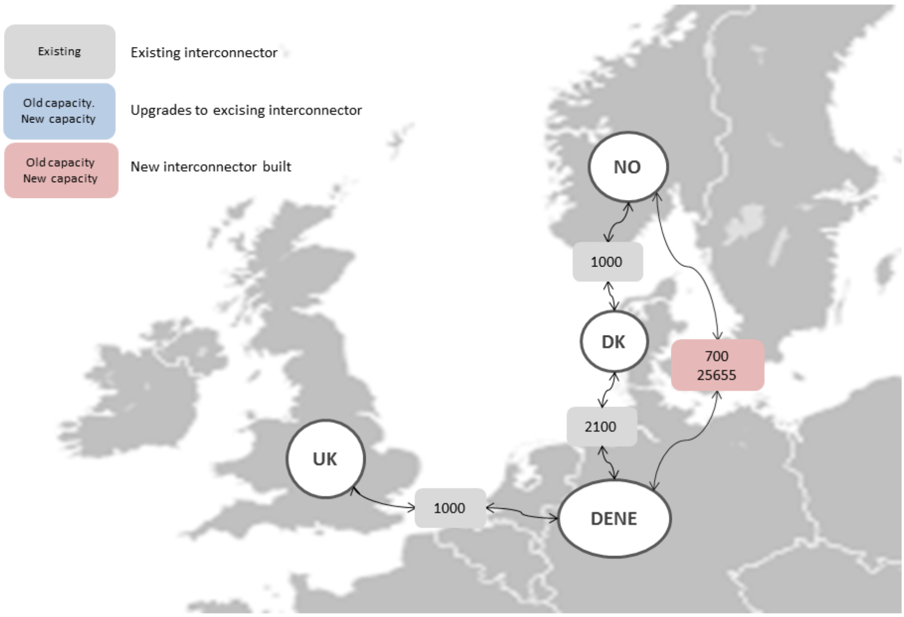

Figure 8.4: Map showing investments given Norway as zonal planner covering all costs. Generation and demand is given in GW. Prices are given in EUR/GWh.

From these results, we see that the optimal strategy for Norway as a zonal leader is very similar as the optimal strategy of supranational planning. Investments are made to the same lines and only differ slightly in magnitude. The welfare allocation is the same. This is not surprising, given the input data to our models. As we have seen in the supranational planning models in Section 8.2.1 and 8.2.2, Norway is the only zone whose welfare increases when investments are made. In order to increase the zonal welfare, Norway invest in lines that facilitate increased exports from Norway to the other countries. The rationale behind this is that Norwegian producers increase their surplus when exports are increased. The final welfare of Norway is lower than for the supranational case, as Norway must cover all investments costs compared to only 25 % in the latter case.

8.3.2 DENE as Zonal Transmission Planner and No Cost Sharing

Letting DENE decide on all transmission investments and covering all costs, we see that the resulting market outcome and investment is the same as the initial market outcome as presented in Section 8.2. Thus DENE cannot increase its welfare by making investment in transmission capacity. We see the same result for Denmark and the UK as well. Thus, given our input data, Norway is the only country benefiting from transmission investments. This result highlights the challenges with different optimal investments plans in transmission planning.

From these results, it looks like Norway experiences a form of prisoner's dilemma. If Norway does not invest, it achieves lower welfare than in the supranational case. However, if Norway does invest, it must cover all investment costs which lowers the zone's social welfare. Yet, Norway achieves higher welfare when investing compared to not investing. Therefore Norway choose to invest in a way that gives the zone a welfare that is closer to the supranational case.

8.3.3 Norway as Zonal Transmission Planner and Bilateral Cost Sharing

This section present the results for the zonal transmission model when we introduce bilateral cost sharing. Market outcome data are presented in Table 8.5 and the transmission investments are displayed in figure 8.5.

	Norway		**Denmark**		**DENE**		**United Kingdom**	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.761	42.884	1.171	1.479	70.225	58.71	24.999	13.351
Demand	15.343	15.529	4.331	4.513	67.125	58.667	38.357	37.714
Price	0.043	0.052	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.219		2.354		31.511		20.255	
PS	0.348		0.126		1.812		0.413	
CS + PS	8.567		2.48		35.323		20.668	
CS + PS - INV	8.545		2.477		35.323		20.648	
Total Investment Cost	0.045							
Total Social Welfare	66.994							
Investments	25.655							

Table 8.5: Market outcome for the zonal planner and bilateral cost sharing. Generation and demand is given in GW. Prices are given in €/GWh.

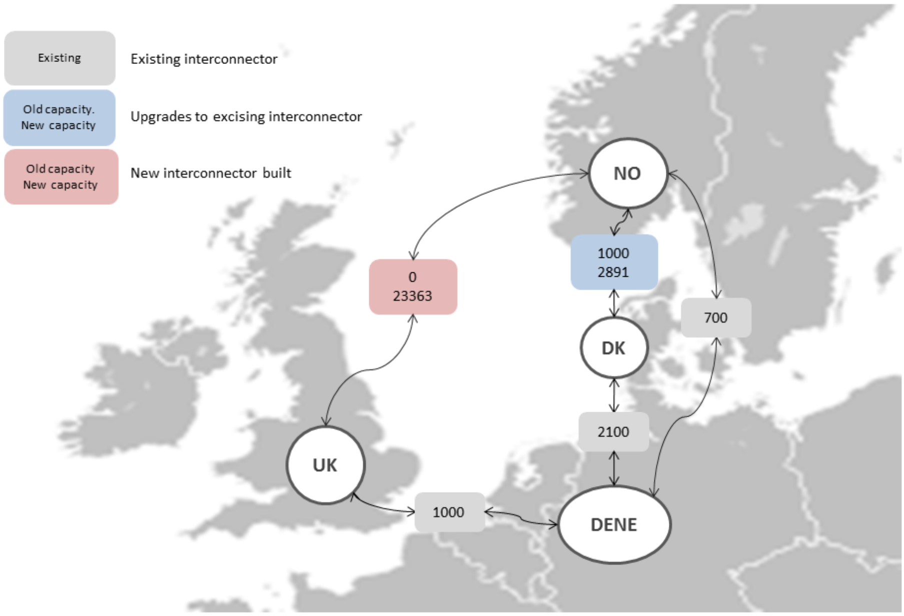

Figure 8.5: Map showing investments given Norway as zonal planner with bilateral cost sharing

From Table 8.5 we see that the market outcome is very similar to when Norway was covering the full cost of investments. In Denmark and DENE generation in 2010 is higher than in the other zonal planning model. In UK, generation in 2010 is lower compared to the other zonal model. Norway chooses to upgrade the line connecting Norway and Denmark, and build a new interconnector between Norway and the UK. The level of the investments are the same as in the supranational and other zonal model. All upgraded lines are used at full capacity in 2020.

We see from Table 8.5 that the welfare in Norway is closer to the welfare in the supranational planner case when we consider bilateral cost sharing than when Norway covers all investment costs. The total social welfare of all countries is the same as for the supranational and zonal model covering all costs model. This can be explained by the fact that the increase in social welfare is mainly a result of increased dispatch of Norwegian hydro power. Hydro power has a lower generation cost than the electricity price in the other zones and welfare is increased if Norway utilize its full hydro power generation capacity. Thus, investments are made on the lines connecting Norway to the other zones. Compared to the situation when Norway covers all investment costs, the social welfare in Norway increase, while welfare in Denmark and DENE decrease. This is to be expected as investment costs are now shared between the zones sharing the upgraded line. Hence, we see that bilateral cost sharing cause a shift in social welfare within the zones in the market. However, total market welfare remains the same as in the other models.

8.3.4 UK as Zonal Transmission Planner and Bilateral Cost Sharing

As we saw in the previous section, Norway invests in a similar fashion both when the country covers all costs associated with the investments and when we introduced bilateral cost sharing. However the social welfare in the country increases when the costs are shared bilaterally because the node only covers half the cost associated with investments. In this section we present the results from the zonal transmission model with bilateral cost sharing and UK as leader. When Norway acts as the transmission planner, a large part of the investments are made on the interconnector between Norway and the UK, however none of the other countries make investments when they are set as leaders. We want to investigate whether bilateral cost sharing can incentivize UK to make an investment.

The results indicate that this is not the case. No investments are made and the welfare outcome in the market is the same as in the initial situation before investments are made. This is not surprising, as we saw that Norway was the only country where welfare increased after upgrades to the grid. Thus, with our input data, non of the other countries benefit from transmission investments and will not make investments if they have to cover any part of the cost.

8.4 Comparison of Short and Long Term Transmission Planning

In this section we illustrate the importance of a long term planning horizon in transmission planning by comparing the resulting social welfare for 2020 when the transmission planner takes both 2010 and 2020 into account when investing to when the planner takes only the current situation into consideration. In the first case the planner has a long term perspective and in the latter care she has a short term planning perspective.

From Table 8.6 we see that the resulting welfare in 2020 is higher when the planner has a long term planning horizon than when the planner only invests based on the current situation. Figure 8.6 show the resulting investments when the upgrades are based on only the current situation. The investments when the planner considers both years was presented in Figure 8.3 in Section 8.2.

From the transmission maps (Figure 8.3 and 8.6) we see that the short term planner invests approximately 7000 MW less than the long term planner. The investments are also made on different lines. The short term planner upgrades the line between

	Short term planner	Long term planner
Social Welfare	67.286	67.363

Table 8.6: Social welfare in different planning scenarios

Norway and DENE and DENE and the UK. She also builds a new line between Norway and the UK. The long term planner also builds a new line between Norway and the UK, but upgrades the line between Norway and Denmark instead of the lines between Norway and DENE and DENE and the UK.

We see that if the short term plan would be built there would be a shortage of transmission capacity in the market by 2020. The lack of sufficient transmission capacity from Norway to the rest of the market would limit the amount of hydro capacity exported, i.e Norway's producer surplus decrease.

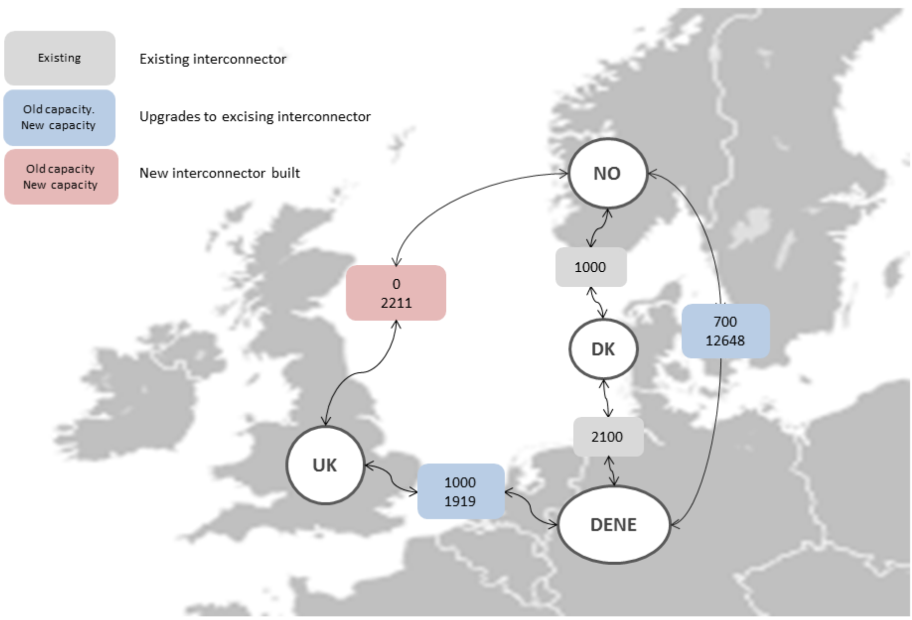

Figure 8.6: Map showing the supranational planner's investments considering only 2010

8.5 Sensitivity Analysis

In order to understand how the models behave when the input data is changed, we perform a sensitivity analysis on selected data. We start by looking at the impact of reducing the number of time periods from four to two time periods has on the model solutions.

As the generation capacity and demand predictions for 2020 are subject to a high level of uncertainty, we choose to see what happens to the models if this data is changed. The changes in these parameters only affected the magnitude of the results and not the conclusions drawn from them, thus we conduct the sensitivity analysis on the supranational transmission planning model.

From conducting the sensitivity analysis, we noticed that somewhat extreme alterations to the input data are required in order to change the conclusions from Section 8.2 and 8.3. When we drastically increased the demand and reduced the generation capacity in DENE, we were able to show that the supranational planning model chose to invest in other lines than our results showed. However, these data changes were highly unrealistic, and we will not elaborate on them further.

8.5.1 Impact of Time Periods

In this section we look at the impact of changing the number of time periods from four to two for the supranational transmission planner. In Section 8.1, we saw that the problem size proved not to be solvable for the zonal transmission planner as this problem is much harder than the model in Chapter 5. Thus, we solved all models for a smaller data set containing two time periods instead of four time periods, in which we lost the seasonal aspect of the models.

To analyze the impact of reducing the number of time periods we compare the results from a supranational planner with two and four time periods. The results show that the investments are done on the same lines. The magnitude of the investment is higher when we consider four time periods. In both versions of the model the electricity prices are the same. We notice that there is a variation in demand, generation and electricity flow between the seasons when we include four time periods. These variations disappear in the two time periods version.

Thus, we see that seasonal variations cause higher investments as some zones may need extra transmission capacity during particular seasons. However, zonal and market social welfare is approximately the same in the four and two time periods models. Thus, even though we loose seasonal insight when reducing the number of time periods we still end up with similar solutions.

8.5.2 Demand 2020

We test the sensitivity of the demand parameter by first increasing and then decreasing the demand in 2020 with 20 % for each zone. All other parameters are fixed. When demand in 2020 increases so does social welfare. Full results can be found in Appendix C

The supranational model invests on the same lines as the original model in Section 8.2.2. The magnitude of the investments have increased as more transmission capacity is needed to provide electricity generated from hydro power to zones with thermal generation capacity. Electricity prices are the same as before as all fuels already were in the generation mix. As consumer welfare increase due to the increased demand, social welfare in all zones increases.

When demand decreases, social welfare decreases in all zones. This is expected due to decreased demand, and in turn consumer welfare. Investments are done on the same lines as before. However, as the need for imports of cheap hydro power has decreased, less investments in capacity is needed. Electricity prices stay the same when changing the demand, due to the same reason mentioned in the previous paragraph. Thus, we conclude that demand data have impact on the amount of social welfare in the market, but neither on where investments are made nor electricity prices. However, changes in demand data does not change the conclusions we reached in Sections 8.2 and 8.3.

8.5.3 Generation Capacity 2020

In this section we test the models sensitivity towards changes in generation capacity in 2020. We first increase and then decrease generation capacity by 50 % in all zones. All other parameters are fixed.

When generation capacity is increased by 50 %, the social welfare of the market increased. Norway is the zone with the highest share of hydro power, which is cheaper than thermal generation. Thus, Norway will export most of its available hydro power generation to zones with a large share of thermal generation. This increases the need for transmission capacity. Even though the level of generation for all fuels increases, thermal generation is still in the production mix which means electricity prices stay the same compared to the supranational plan in Section 8.2.2. Producers experience a higher profit than in the supranational case as they have more cheap generation they can sell at a high price. This cause an increase of the overall social welfare in the market.

As generation capacity goes down, so does social welfare. The amount of generation cheaper than thermal is reduced, i.e there is less exports in the market. This reduces the need for additional transmission capacity. The model still invests on the same lines, however the upgrades are small compared to the supranational model in section 8.2.2. Producer surplus in reduced as the amount of cheap generation has decreased. Thus, social welfare decrease in all zones. From these results, we conclude that 2020 generation capacity data have impact on the level of investments made in the market. However, changes in generation capacity do not alter the overall conclusions.

8.5.4 Generation Capacity and Demand in 2020

In this section we look at the impact of changing generation and demand data in 2020 simultaneously. The 2020 generation capacity for all fuels are reduced by 50 %. Demand is increased by 20 % in all zones. All other parameters are fixed.

With the generation and demand data altered, the supranational model still choose to invest on the same lines as in the supranational model in Section 8.2.2. The level of investments are lower compared to the results of the original model. Norway choose to export electricity to the other zones, as Norway has a large share of hydro power and electricity prices are higher than the generation cost for hydro power. Compared to the solution of the supranational model in section 8.2.2, producer surplus is lower as profits are reduced. However, the increased demand has a positive impact on consumer welfare in all zones. Thus, social welfare increase when changing generation capacity and demand data for 2020 simultaneously.

8.5.5 Concluding Remarks

This sensitivity analysis have showed that the data does not impact the overall decision on where to invest, but how much to invest. Thus, data must be chosen carefully, as using the "wrong" data can lead to over-or under-investments, which in turn reduce social welfare.

Chapter 9

Discussion and Further Work

In this chapter we discuss the various limitations of the model and methods used and consider possible extensions. Some limitations are discussed in Section 9.1 and assumptions affecting the validity of the results are discussed in Section 9.2. Section 9.3 discusses the limitations of the solution approach. Some policy implications based on research insights are given in Section 9.4 and the chapter concludes with some suggestions for further work in Section 9.5.

9.1 Limitations of the Model

Many simplifications and assumptions are made when building a model. This is a natural part of modeling. There is a trade off between a realistic representation and the ease, or even possibility, of computing a solution. It is however important to be aware of how these simplifications and assumptions influence the quality of the solution.

The main limitations of our model is the technical representation of the grid, the exogenous generation capacity, the lack of uncertainty in modeling the renewable sources and the time resolution. Also the model only considers economic aspects. Other objectives like reliability of the power system or minimization of unused capacity is no taken into account.

We have modeled the flow in the network by pure transportation using one directional arc-flows. With this approach we omit losses, ramping conditions on transmission lines and Kirchoff's laws. The main limitation of this is the lack of representation of loop flows. A full AC representation of the grid would solve this, but would also cause the feasible region to be non-linear and non-convex, including trigonometric functions. We use the Baron solver (Sahinidis, 2013) to solve our model. This solver handles non-convexities and non-linearities, but does not yet handle trigonometric functions. Consequently an AC representation does not work with our solution approach. The DC load flow approach results in a linear feasible region and represents loop flows in a good way. This approach was not used because our model only considers cross border interconnectors and not the distribution grid within the countries, and thus has a high aggregation level. Modeling of the distribution and transmission grids within the individual countries is beyond the scope of this thesis, but could be an interesting extension.

The generation capacities are given as parameters to the model. This does not allow us to consider possible generation capacity investment responses to changes in the transmission topology. New transmission capacity will affect the market clearing and can thus provide incentives for power generators to invest in new generation capacity. See for example Sauma and Oren (2006) or Pozo et al. (2013) for a discussion of this effect. However, because we include two different years in our data set, the transmission planner does have to plan for two different generation capacity situations. As we saw in the results chapter in Section 8.3 the different generation capacity situations do affect the optimal transmission expansion plans. The 2020 generation capacities are based on various projections and one can assume that in some sense these projections constitute generation capacity investment responses to market developments, among them transmission extensions. Thus we do not endogenously consider the generation capacity investment response, but the transmission planner has to consider both the generation capacity today and changing capacities in the future.

The model is deterministic and has a seasonal or yearly time resolution depending on the size of the problem instance. As we saw in the results chapter 8 the lack of stochasticity in the modeling of renewable sources cause the model to rely too much on these. The supply of renewable sources is uncertain and dependent on stochastic climatic factors. Furthermore future investments in new renewable generation capacity is dependent on the development of various renewable energy support schemes. The outcomes of these decisions are not certain.

The combination of no uncertainty in available generation capacity and marginal cost equal to zero makes the renewable sources very attractive. It is basically free generation capacity. Uncertainty could reduce the utilization of these sources and increase willingness to pay for transmission capacity.

We represent the seasonality of renewable sources using capacity factors, but supply also varies throughout the day. To be able to capture this effect a higher time resolution is necessary, but due to the long solution time for even small problem instances we did not increase the time resolution.

The objective function maximizes the sum of consumer and producer surplus less transmission investment cost and thus limits the model to considering economic aspects. The reliability of the grid, the amount of undispatched capacity and the amount of renewable sources in the energy mix are also important aspects to consider when planning transmission expansions. Including reliability of the power system as a variable to be maximized by the transmission planner could for instance reduce the utilization of variable energy sources. However we considered the economic aspects to be most important when analyzing national strategic investments.

Despite many limitations we believe that our model provides research insight into national strategic investments in transmission capacity.

9.2 Validity of Results

As discussed in Section 6.5 the assumptions made in the data set will affect the quality of the solution. Furthermore the problem instance had to be reduced to be able to solve the zonal planner's problem in reasonable time.

The original data set includes six nodes representing Norway, Sweden, Denmark, Germany, Netherlands and the United Kingdom. The data set also has eight different fuels and four time periods. This allowed us to model a diverse generation portfolio and two seasons per year. The countries represented are most of the countries comprised in the North and Baltic Seas Grid infrastructure project. This is one of the large infrastructure projects mentioned in Section 2.2 and the number one priority project for "European infrastructure projects for 2020 and beyond" (European Comission, 2010b). Thus we consider this a reasonable selection of countries to model, and the data set to be large enough to give insights into national strategic investments in transmission capacity in this region.

In the reduced problem instance we omit Sweden, aggregate Germany and the Netherlands in one node, aggregate all thermal capacity, and include only two time periods. This affects the validity of the results in a negative direction. The most important countries with respect to generation mix are still included in the model, but the reduction of time periods means we no longer represent the seasonality of the renewable generation capacity. This means we no longer represent any variability and these sources basically have the same characteristics as other energy sources in the model.

When variability of renewable energy sources and reliability of the grid is not considered by the model the utilization of variable renewable energy becomes too high compared to a more realistic situation. If these aspects were modeled we may have seen that other countries than Norway could have benefited from transmission investments.

The validity of the results is also affected by the fact that the national power grids will probably not be able to handle the interconnector upgrades planned by the model. A more realistic outcome could be produced by modeling the national transmission grids or include a capacity restriction on the transmission investments to a capacity that the national power grids are likely to be able to handle. This however raises the nontrivial issue of how to determine this capacity.

We represent demand using a linear inverse demand curve. This is a fair assumption to make. It is a very common simplification and allows us to identify marginal improvements in consumer surplus. However the demand functions are calculated based on the same price for all countries in the data set. In reality the prices differ across countries.

Due to the large amounts of hydroelectric generation capacity in Norway and Sweden, a better representation of the water values would be an advantage. This would allow us to take into account the flexibility of hydro power and the effect of dry and wet years. The water values are in reality specific for each individual reservoir. This is among other things due the filling degrees in the reservoirs. One solution could be to calculate the water values using a separate model and then feed these in to our model. This is however beyond the scope of this thesis.

We have also excluded some generation capacity, like geothermal, run of river and pumped storage, from the model. The generation capacity from these sources is relatively small compared to other sources, however adding them to the model would add realism.

9.3 Limitations of the Solution Method

The zonal planner's problem is difficult to solve due to the complexity of the objective function and the disjunctive constraint representation of the feasible region. One important weakness of the disjunctive constraint approach is how sensitive it is to the choice of the K-parameters. Poorly chosen values of these parameters could cause numerical errors or even cut the optimal solution from the feasible region. Furthermore a large number of binary variables are added to the problem when this approach is used, and this increases the difficulty of solving the problem.

The objective function in the upper level of the zonal planner's problem is non-linear and non-convex. Consequently it is hard to find a global optimal solution as was discussed in Section 2.5 and as we saw when investigating the solution times in Section 8.1. We have used the BARON solver to solve the problem. The solver handles the non-convexities of the objective function for small instances, but larger instances can not be solved within reasonable time. In some cases the first feasible solution found turns out to be the optimal solution and most of the solution time is spent on proving optimality. In other cases new and better feasible solutions are found throughout the solution time. This confirms known difficulties with global optimization as discussed in Section 2.5.

A different representation of the feasible region without binary variables could help reduce the solution time, but the non-linear and non-convex objective function renders the problem difficult regardless of this.

9.4 Policy Implications

Transmission expansion may change the allocation of costs and benefits in a meshed network. Both different stakeholders in the power market and nations as a whole could be affected. This possible re-allocation of benefits arising from transmission capacity extensions in meshed networks should be taken into account when designing policies to incentivice the building of additional capacity.

Different national states could have incentive to under- or over invest compared to the supranationally optimal solution. Moreover different national states could have conflicting optimal plans. Thus it is difficult to find an equilibrium between the different national strategic planners.

Both benefits and costs have to be taken into account in order to find an equilibrium. As long as transmission planning is a national prerogative supranational plans have to be incentive compatible to be accepted by all nations involved. Political feasibility of transmission investment decisions depend on acceptable cost and benefit allocations, thus there is a need to better understand the effect of transmission expansion on the distribution of welfare.

One approach is to design good compensation mechanisms. The European inter-TSO compensation mechanism, which is meant to compensate TSOs for the costs associated with hosting transit flows, is an example of such a mechanism. Results from our models indicate that welfare increases can be large compared to the necessary investment costs. Thus a compensation mechanism to reallocate some of the benefits associated with investments could be a feasible approach. One major difficulty in designing compensation mechanisms is to define a benchmark against which to compare the increase or decrease in costs and benefits resulting from a capacity investment, and to isolate the effect of transmission investments from other developments in the energy market.

Another approach could be to develop an EU wide organization for supranational network planning. In Australia and the US there has been a clear policy move towards "the introduction of a single entity with planning responsibility" (Frontier Economics Ltd., 2008). These planning entities are usually partly independent with respect to the interests of other agents in the power market. Thus this constitutes a move towards more supranational planning.

The main implication is that policy makers have to be aware of the possible re-allocations of welfare caused by transmission investments when designing new policies. This re-allocation also complicates the identification of new projects for further development and presupposes better cooperation between TSOs.

9.5 Further Work

The models proposed in this thesis can be further improved by addressing some of the weaknesses discussed in this chapter.

As discussed in Section 9.1 a significant assumption made is to have no restrictions on the transmission investment. In doing this we implicitly assume that the national transmission and distribution grids are able to handle the new capacities of the interconnectors. This is probably not the case. Norway, Sweden and Denmark are for instance divided into price areas due to internal congestion. Therefore a good extension would be to include national grids to the model. This could be done in a simplified way by dividing the countries into regions and include investments in transmission capacity between the regions within a country.

Other details that could be added to the model are higher time resolution, technical constraints on the grid and generation capacity and exogenous water values from a separate model. Adding uncertainty to the model by letting renewable power generation be stochastic would be interesting, and would also add more realism to the model. However adding these features to the model would also increase the size of the problem and hence the solution time. Given the current solution time we would not recommend this as a first choice for further work.

Due to long solution times further research should be directed towards improvements to the solution method. Investigation into the possibilities of linearizing the objective function could also help reduce the solution time. A representation of the feasible region like those presented in Ruiz et al. (2012) and Huppmann and Egerer (2014) could also improve the solution time as binary variables are avoided. The development of a heuristic solution method could also be a path for further research.

The model could also be used to analyze the effect of various compensation mechanisms and cost sharing regimes. As discussed in relation to the policy implications in Section 9.4, better understanding of how such mechanisms affect the distribution of welfare is needed in order to move towards a supranational planning solution.

The MPEC could also be used to model an EPEC to model a multiple leader, common follower situation where each country act as a leader and the market clearing in the common power market constitute the follower as is done in Bjus and Belmans (2012).

Chapter 10

Concluding Remarks

In this master's thesis we have analyzed national strategic investments in transmission capacity using a bi-level model where a transmission planner decides on transmission investments on the upper level and the lower level represents the market clearing in the power market. National strategic investments refers to the fact that different transmission investment plans can change the welfare distribution between countries in a meshed network, and consequently different nations can decide on transmission investments strategically to maximize the welfare in their country.

The research on national strategic investments in transmission capacity is motivated by the necessary upgrades of the European transmission grid to be able to meet the growing demand for electricity.

Moreover new flow patterns caused by increased trade due to electricity market liberalization and increased shares of renewable energy in the energy mix is causing increased stress on the grid. Increased market coupling of the national energy markets in the EU also means transmission capacity upgrades are becoming an increasingly multilateral question.

We analyzed national strategic investments by comparing a supranational planner to a zonal planner. The supranational planner maximizes the welfare of all nodes in a market, whereas the zonal planner maximizes the welfare of a single node. For the zonal planner we compared a situation where the zonal planner has to bear all the costs associated with network upgrades and a bilateral cost sharing situation. When the costs are shared bilaterally each country pays half the investment cost for any line connected to it.

The model for the supranational planner reduced to a single level optimization problem as the objectives of the upper and lower level were aligned. This problem solved easily for the instances we tested. When we considered the zonal planner, the objectives of the upper and lower level no longer aligned and we had to solve an

MPEC. We used a disjunctive constraint approach to represent the complementary constraints of the lower level when we solved the MPEC. This resulted in a large number of binary variables which increased the difficulty of solving the problem.

Furthermore the objective function of the upper level problem is non-linear and non-convex, rendering the problem quite difficult to solve. We used the BARON solver (Sahinidis, 2013) in GAMS, which is able to handle non-linearities and non-convexities, but we were only able to solve the MPEC for small problem instances.

We tested the model on a data set representing countries in Northern Europe. The results showed that the optimal investment plans differed between different leader nodes. This illustrates the difficulty of finding an equilibrium for a set of individual planners.

When we looked closer at the resulting welfare of the node representing Norway we found an interesting result. The resulting welfare of Norway was higher when we looked at the results from the supranational planner than when Norway acted as the leader node. This is counter intuitive. One would expect a node to obtain higher welfare as leader than as part of the market. This could indicate a form of prisoner's dilemma situation where Norway looses when investing, but looses even more when not investing. This hypothesis was confirmed by running the zonal planner model with Norway as leader and the investments fixed to zero, and seeing that the resulting welfare for Norway was lower here than when it was able to make investments. Thus it seamed like the welfare was reduced because the leader node had to pay the full costs of making the transmission investment. This was confirmed when we introduced bilateral cost sharing, meaning the leader no longer incurred all the transmission investment costs, and the welfare in Norway increased compared to when Norway had to pay all the investment costs. If we compare these results to the benchmark result before any investments are made we see that Norway is the only node whose welfare increase when the supranational planner makes investments.

Our model takes two different years, 2010 and 2020, into account when deciding on the optimal transmission investments. This done because transmission investments are long term. We illustrate the importance of this long term perspective by comparing the optimal investment plans resulting from a supranational planner considering only a single year. We see that these plans are different from each other, and that the optimal plan for the 2010 situation is no longer optimal in 2020.

Initially our data set included four time periods. This allowed us to split a year into two seasons, winter an summer. This was done to include variations in demand and in the supply from renewable sources. However we had to reduce the problem instance to two time periods to be able to solve the model for the zonal planner. In our sensitivity analysis we therefore investigated the effect of reducing the number of time periods by comparing the solution for the supranational planner for two and four time periods. Here we saw that the increased variability obtained by including seasons increased the transmission investments, but the investments were made on the same lines as when seasons were not included. Thus the overall conclusion stays the same when seasonality is excluded from the model. We also conduct a sensitivity analysis on demand and generation data and saw that changing these parameters have a large impact on the overall results from the model.

The results from our model indicate that policy makers have to be aware of the possible re-allocations of welfare caused by transmission investments when designing new policies. We saw that in general investment costs were low compared to the welfare gain in the market when we considered the supranational planner. This motivates research into the development of good compensation mechanisms to control the distribution of costs and benefits in the market in order to facilitate a move towards a supranationally optimal solution.

Although the presented models does not include all aspects of the power market, we have demonstrated that it can be used to provide insight into national strategic investments in transmission capacity. Further work should focus on improving the solution method in order to reduce the solution time so further details can be added to the model.

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Appendices

Appendix A

Zonal Transmission Planner Reformulation Using Disjunctive Constraints

The complete mixed integer linear problem formulation of the MPEC problem for the zonal planner includes both the discrete linearization of the non-linear terms in the objective function and the disjunctive formulation of the lower level constraints. The resulting model formulation is as follows:

A.1 Leader covers all costs

$$\begin{aligned} min \ \ w = & \sum_{n \in N_l, t} (-0.5 \cdot B_{n,t} \cdot d^2_{n,t}) \\ + \sum_{n \in N_l, f, t} & C^{GEN}_{n,f,t} \cdot q^{prod}_{n,f,t} - \sum_{m,t} p_{m,t} \cdot q^{sold}_{n,m} \\ - \sum_{m,t} flow_{n,m,t} * p^t_{n,m,t} + & \sum_{n,m} C^{INV}_{n,m} \cdot x_{n,m} \quad \forall m \end{aligned} \tag{A.1}$$

s.t

$$x_{n,m} \leq 100 \tag{A.2}$$

$$- A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \ \ \geq \ \ 0 \tag{A.3}$$

$$-A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \quad \leq \quad K^{1a} \cdot r^1_{n,t} \tag{A.4}$$

$$d_{n,t} - K^{1b} \cdot \left(1 - r^1_{n,t}\right) \quad \leq \quad 0 \tag{A.5}$$

$$CG_{n,f,t} + \gamma_{n,f,t} + \phi_{n,t} \quad \geq \quad 0 \tag{A.6}$$

$$CG_{n,f,t} + \gamma_{n,f,t} + \phi_{n,t} \quad \leq \quad K^{2a} \cdot r^2_{n,f,t} \tag{A.7}$$

$$q^{prod}_{n,f,t} - K^{2b} \cdot \left(1 - r^2_{n,f,t}\right) \quad \leq \quad 0 \tag{A.8}$$

$$-\phi_{n,t} - p^t_{n,m,t} - p^{el}_{m,t} \quad \geq \quad 0 \tag{A.9}$$

$$-\phi_{n,t} - p^t_{n,m,t} - p^{el}_{m,t} \quad \leq \quad K^{3a} \cdot r^3_{n,m,t} \tag{A.10}$$

$$q^{sold}_{n,m,t} - K^{3b} \cdot \left(1 - r^3_{n,m,t}\right) \quad \leq \quad 0 \tag{A.11}$$

$$\epsilon_{n,m,t} + \epsilon_{m,n,t} + p^t_{n,m,t} \quad \geq \quad 0 \tag{A.12}$$

$$\epsilon_{n,m,t} + \epsilon_{m,n,t} + p^t_{n,m,t} \quad \leq \quad K^{4a} \cdot r^4_{n,m,t} \tag{A.13}$$

$$flow_{n,m,t} - K^{4b} \cdot \left(1 - r^4_{n,m,t}\right) \quad \leq \quad 0 \tag{A.14}$$

$$-q^{prod}_{n,f,t} + CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \quad \geq \quad 0 \tag{A.15}$$

$$-q^{prod}_{n,f,t} + CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \quad \leq \quad K^{5a} \cdot r^5_{n,f,t} \tag{A.16}$$

$$\gamma_{n,f,t} - K^{5b} \cdot \left(1 - r^5_{n,f,t}\right) \quad \leq \quad 0 \tag{A.17}$$

$$\sum_f q^{prod}_{n,f,t} - \sum_m q^{sold}_{n,m,t} = 0 \tag{A.18}$$

$$flow_{n,m,t} - q^{sold}_{n,m,t} = 0 \tag{A.19}$$

$$-flow_{n,m,t} + CAP^T_{n,m,t} + x_{n,m} + x_{m,n} \quad \geq \quad 0 \ \ \forall n = 1 \tag{A.20}$$

$$-flow_{n,m,t} + CAP^T_{n,m,t} + x_{n,m} + x_{m,n} \quad \leq \quad K^{6a} \cdot r^6_{n,m} \ \ \forall n \in N_l \tag{A.21}$$

$$\epsilon_{n,m,t} - K^{6b} \cdot \left(1 - r^6_{n,m,t}\right) \quad \leq \quad 0 \tag{A.22}$$

$$d_{n,t} - \sum_m q^{sold}_{n,m,t} \quad = \quad 0 \tag{A.23}$$

A.2 Bilateral cost sharing

$$\begin{aligned} min \ \ w = & \sum_{n \in N_l, t} (-0.5 \cdot B_{n,t} \cdot d^2_{n,t}) \\ + \sum_{n \in N_l, f, t} & C^{GEN}_{n,f,t} \cdot q^{prod}_{n,f,t} - \sum_{m,t} p_{m,t} \cdot q^{sold}_{n,m} \\ -\sum_{m,t} flow_{n,m,t} * p^t_{n,m,t} + \sum_{n,m} & 0.5 \cdot C^{INV}_{n,m} \cdot x_{n,m} \quad \forall m \end{aligned} \tag{A.24}$$

s.t

$$x_{n,m} \leq 100 \tag{A.25}$$

$$-A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \quad \geq \quad 0 \tag{A.26}$$

$$-A_{n,t} + B_{n,t} \cdot d_{n,t} + p^{el}_{n,t} \quad \leq \quad K^{1a} \cdot r^1_{n,t} \tag{A.27}$$

$$d_{n,t} - K^{1b} \cdot \left(1 - r^1_{n,t}\right) \quad \leq \quad 0 \tag{A.28}$$

$$CG_{n,f,t} + \gamma_{n,f,t} + \phi_{n,t} \quad \geq \quad 0 \tag{A.29}$$

$$CG_{n,f,t} + \gamma_{n,f,t} + \phi_{n,t} \quad \leq \quad K^{2a} \cdot r^2_{n,f,t} \tag{A.30}$$

$$q^{prod}_{n,f,t} - K^{2b} \cdot \left(1 - r^2_{n,f,t}\right) \quad \leq \quad 0 \tag{A.31}$$

$$- \phi_{n,t} - p^t_{n,m,t} - p^{el}_{m,t} \quad \geq \quad 0 \tag{A.32}$$

$$- \phi_{n,t} - p^t_{n,m,t} - p^{el}_{m,t} \quad \leq \quad K^{3a} \cdot r^3_{n,m,t} \tag{A.33}$$

$$q^{sold}_{n,m,t} - K^{3b} \cdot \left(1 - r^3_{n,m,t}\right) \quad \leq \quad 0 \tag{A.34}$$

$$\epsilon_{n,m,t} + \epsilon_{m,n,t} + p^t_{n,m,t} \quad \geq \quad 0 \tag{A.35}$$

$$\epsilon_{n,m,t} + \epsilon_{m,n,t} + p^t_{n,m,t} \quad \leq \quad K^{4a} \cdot r^4_{n,m,t} \tag{A.36}$$

$$flow_{n,m,t} - K^{4b} \cdot \left(1 - r^4_{n,m,t}\right) \quad \leq \quad 0 \tag{A.37}$$

$$0 \quad \leq \quad 0.5 \cdot C^{INV}_{n,m} - \sum_t (\epsilon_{n,m,t} + \epsilon_{m,n,t}) \quad \geq \quad 0 \tag{A.38}$$

$$0 \quad \leq \quad 0.5 \cdot C^{INV}_{n,m} - \sum_t (\epsilon_{n,m,t} + \epsilon_{m,n,t}) \quad \leq \quad K^{7a} \cdot r^7_{n,m} \tag{A.39}$$

$$x_{n,m} - K^{7b} \cdot \left(1 - r^7_{n,m}\right) \quad \leq \quad 0 \tag{A.40}$$

$$- q^{prod}_{n,f,t} + CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \quad \geq \quad 0 \tag{A.41}$$

$$- q^{prod}_{n,f,t} + CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \quad \leq \quad K^{5a} \cdot r^5_{n,f,t} \tag{A.42}$$

$$\gamma_{n,f,t} - K^{5b} \cdot \left(1 - r^5_{n,f,t}\right) \quad \leq \quad 0 \tag{A.43}$$

$$\sum_f q^{prod}_{n,f,t} - \sum_m q^{sold}_{n,m,t} = 0 \tag{A.44}$$

$$flow_{n,m,t} - q^{sold}_{n,m,t} = 0 \tag{A.45}$$

$$- flow_{n,m,t} + CAP^{T}_{n,m,t} + x_{n,m} + x_{m,n} \geq 0 \;\; \forall n = 1 \tag{A.46}$$

$$- flow_{n,m,t} + CAP^{T}_{n,m,t} + x_{n,m} + x_{m,n} \leq K^{6a} \cdot r^{6}_{n,m} \;\; \forall n \in N_l \tag{A.47}$$

$$\epsilon_{n,m,t} - K^{6b} \cdot \left(1 - r^{6}_{n,m,t}\right) \leq 0 \tag{A.48}$$

$$d_{n,t} - \sum_{m} q^{sold}_{n,m,t} = 0 \tag{A.49}$$

Appendix B

Zonal Transmission Model with Bilateral Cost Sharing

$$
\begin{aligned}
min \;\; w = & \sum_{n \in N_l, t} (-A_{n,t} \cdot d_{n,t} + 0.5 \cdot B_{n,t} \cdot d_{n,t}^2 + p_{n,t} \cdot d_{n,t}) \\
& + \sum_{n \in N_l, f, t} CG_{n,f,t} \cdot q_{n,f,t}^{prod} - \sum_{n \in N_l, f, t} p_{n,t} \cdot q_{n,f,t}^{prod} \\
& + \sum_{n \in N^l, m} \left(0.5 \cdot C_{n,m}^{INV} \cdot x_{n,m}\right) \quad \forall m
\end{aligned}
\tag{B.1}
$$

s.t

$$
0 \leq x_{n,m} \geq 0 \tag{B.2}
$$

s.t

$$
0 \;\; \leq \;\; -A_{n,t} + B_{n,t} \cdot d_{n,t} + p_{n,t}^{el} \;\; \geq \;\; 0 \;\; \perp \;\; d_{n,t} \geq 0 \tag{B.3}
$$

$$
0 \;\; \leq \;\; C_{n,f,t}^{GEN} + \gamma_{n,f,t} + \phi_{n,t} \;\; \geq \;\; 0 \;\; \perp \;\; q_{n,f,t}^{prod} \geq 0 \tag{B.4}
$$

$$
0 \;\; \leq \;\; -\phi_{n,t} - p_{n,m,t}^{t} - p_{m,t}^{el} \;\; \geq \;\; 0 \;\; \perp \;\; q_{n,m,t}^{sold} \geq 0 \tag{B.5}
$$

$$
0 \;\; \leq \;\; \epsilon_{n,m,t} + \epsilon_{m,n,t} + p_{n,m,t}^{t} \;\; \geq \;\; 0 \;\; \perp \;\; flow_{n,m,t} \geq 0 \tag{B.6}
$$

$$0 \quad \leq \quad 0.5 \cdot C^{INV}_{n,m} - \sum_t (\epsilon_{n,m,t} - \epsilon_{m,n,t}) \quad \geq \quad \perp \quad x_{n,m} \geq 0 \tag{B.7}$$

$$0 \quad \leq \quad -q^{prod}_{n,f,t} + CAP^{GEN}_{n,f,t} \cdot AV_{n,f,t} \quad \geq \quad 0 \quad \perp \quad \gamma_{n,f,t} \geq 0 \tag{B.8}$$

$$\sum_f q^{prod}_{n,f,t} - \sum_m q^{sold}_{n,m,t} = 0 \quad \perp \quad \phi_{n,t} \ \ \textit{free} \tag{B.9}$$

$$flow_{n,m,t} = q^{sold}_{n,m} \quad \perp \quad p^t_{n,m} \ \ \textit{free} \tag{B.10}$$

$$0 \quad \leq \quad -flow_{n,m,t} + CAP^T_{n,m,t} + x_{n,m} + x_{m,n} \quad \geq \quad 0 \quad \perp \quad \epsilon_{n,m,t} \geq 0 \tag{B.11}$$

$$d_n = \sum_m q^{sold}_{n,m,t} \quad \perp \quad p^{el}_n \ \ \textit{free} \tag{B.12}$$

Appendix C

Results Sensitivity Analysis

C.1 Sensitivity of Demand

C.1.1 Demand Down

	Norway		Denmark		DENE		The UK	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.761	42.884	2.099	1.479	70.471	47.986	23.878	7.666
Demand	15.343	12.612	4.331	3.544	67.125	52.800	38.357	31.059
Price	0.043	0.050	0.043	0.052	0.043	0.052	0.043	0.052
CS	7.460		2.098		31.962		18.498	
PS	0.326		0.126		1.812		0.413	
CS + PS	7.786		2.225		33.774		18.911	
Investment Cost	0.049							
Total Social Welfare	62.648							
Investments	28.823							

Table C.1: Market outcome supranational model with demand decreased by 20 %

C.1.2 Demand Up

	Norway		Denmark		DENE		The UK	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.655	42.884	2.207	1.479	68.292	87.300	26.001	23.729
Demand	15.343	18.266	4.331	5.126	67.125	88.000	38.357	44.000
Price	0.043	0.050	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.957		2.516		41.255		21.915	
PS	0.317		0.126		1.812		0.413	
CS + PS	9.274		2.643		43.067		22.328	
Investment Cost	0.039							
Total Social Welfare	77.272							
Investments	22.941							

Table C.2: Market outcome supranational model with demand increased by 20 %

C.2 Sensitivity of Generation

C.2.1 Generation Down

	Norway		Denmark		DENE		The UK	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.524	19.195	1.171	4.956	65.507	59.318	30.003	32.954
Demand	15.391	15.529	4.331	4.513	67.125	58.667	38.357	44
Price	0.041	0.052	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.245		2.354		33.511		20.255	
PS	0.160		0.081		0.857		0.150	
CS + PS	8.405		2.430		34.363		20.401	
Investments	11.432							
Investment Cost	0.019							
Social Welfare	65.599							

Table C.3: Market outcome supranational model with generation decreased by 50 %

C.2.2 Generaton Up

	Norway		Denmark		DENE		The UK	
	2010	2002	2010	2020	2010	2020	2010	2020
Generation	28.761	60.413	3.023	2.381	78.300	46.243	15.072	7.436
Demand	15.343	15.579	4.331	4.513	67.125	58.667	38.357	37.714
Price	0.043	0.050	0.043	0.052	0.043	0.052	0.043	0.052
CS	8.245		2.354		35.511		20.255	
PS	0.369		0.173		1.860		0.322	
CS + PS	8.614		2.509		35.353		20.559	
Investments	11.432							
Investment Cost	0.073							
Social Welfare	67.035							

Table C.4: Market outcome supranational model generation increased by 50 %

C.3 Supranational Model with Four Time Periods

	Norway				Denmark				DENE				The UK			
Generation	28.572	28.713	43.162	42.606	4.783	0.803	1.945	1.012	68.608	54.312	56.307	36.975	32.144	31.238	30.659	25.202
Demand	18.697	11.859	19.00	12.353	4.783	3.831	4.984	3.991	68.556	64.571	67.556	55.375	44.071	34.769	40.533	34.077
Price	0.043	0.043	0.052	0.050	0.043	0.043	0.052	0.052	0.043	0.043	0.052	0.052	0.043	0.043	0.052	0.052
CS	16.979				4.740				68.545				41.324			
PS	0.369				1.860				3.624				0.825			
CS + PS	17.653				4.993				72.169				42.149			
Investments	28.554															
Investment Cost	0.049															
Social Welfare	136.916															

Table C.5: Market outcome supranational model with four time periods

Appendix D

Gams Code

D.1 Supranational Transmission Model

```
Sets
n nodes /n1*n6/
f fuels /f1*f8/
t time /t1*t4/

$ontext
nodes: 1   2   3   4   5   6
       NO  SE  DK  DE  NL  GB

fuels:
1      2    3     4       5        6      7      8
Coal  Gas  Oil  Nuclear  Hydro   Wind   Solar  Bio
$offtext

alias (n,m);

table A(n,t)
*Intercept of inverse demand curve in node n and time t
*  W2010  S2010  W2020  S2020
   t1     t2     t3     t4
n1 0.660  0.495  0.660  0.495
n2 0.660  0.495  0.660  0.495
n3 0.660  0.495  0.660  0.495
n4 0.660  0.495  0.660  0.495
n5 0.660  0.495  0.660  0.495
n6 0.660  0.495  0.660  0.495
;

table B(n,t)
*Slope of inverse demand curve in node n and time t
*  W2010  S2010  W2020  S2020
   t1     t2     t3     t4
n1 0.033  0.038  0.033  0.038
```

```
n2 0.029  0.032  0.029  0.032
n3 0.129  0.118  0.129  0.118
n4 0.009  0.007  0.009  0.007
n5 0.043  0.043  0.043  0.043
n6 0.014  0.014  0.014  0.014
;


table CG(n,f,t)
*Generation cost for fuel f in node n [EUR/GW]
*      W2010  S2010  W2020  S2020
        t1       t2       t3      t4
n1.f1  0.036    0.036    0.044  0.044
n1.f2  0.061    0.061    0.072  0.072
n1.f3  0.150    0.150    0.179  0.179
n1.f4  0.0095   0.0095   0.011  0.011
n1.f5  0.040    0.040    0.047  0.047
n1.f6  0        0        0      0
n1.f7  0        0        0      0
n1.f8  0.029    0.029    0.034  0.034
n2.f1  0.036    0.036    0.044  0.044
n2.f2  0.061    0.061    0.072  0.072
n2.f3  0.150    0.150    0.179  0.179
n2.f4  0.0095   0.0095   0.011  0.011
n2.f5  0.040    0.040    0.047  0.047
n2.f6  0        0        0      0
n2.f7  0        0        0      0
n2.f8  0.029   0.029    0.034  0.034
n3.f1  0.036   0.036    0.044  0.044
n3.f2  0.061   0.061    0.072  0.072
n3.f3  0.150   0.150    0.179  0.179
n3.f4  0.0095  0.0095   0.011  0.011
n3.f5  0.040   0.040    0.047  0.047
n3.f6  0        0        0      0
n3.f7  0        0        0      0
n3.f8  0.029   0.029   0.034  0.034
n4.f1  0.036   0.036   0.044  0.044
n4.f2  0.061   0.061   0.072  0.072
n4.f3  0.150   0.150   0.179  0.179
n4.f4  0.0095  0.0095  0.011  0.011
n4.f5  0.040   0.040   0.047  0.047
n4.f6  0       0       0      0
n4.f7  0       0       0      0
n4.f8  0.029   0.029   0.034  0.034
n5.f1  0.036   0.036   0.044  0.044
n5.f2  0.061   0.061   0.072  0.072
n5.f3  0.150   0.150   0.179  0.179
n5.f4  0.0095  0.0095  0.011  0.011
n5.f5  0.040   0.040   0.047  0.047
n5.f6  0       0       0      0
n5.f7  0       0       0      0
n5.f8  0.029   0.029   0.034  0.034
n6.f1  0.036   0.036   0.044  0.044
n6.f2  0.0375  0.0375  0.072  0.072
n6.f3  0.150   0.150   0.179  0.179
n6.f4  0.0095  0.0095  0.011  0.011
n6.f5  0.040   0.040   0.047  0.047
```

```
n6.f6   0        0        0       0
n6.f7   0        0        0       0
n6.f8   0.029    0.029    0.034   0.034
;


table GCAP(n,f,t)
*Generation capacity of fuel f in node n in time t [GW]
*  W2010  S2010  W2020  S2020
        t1      t2      t3      t4
n1.f1   0       0       0       0
n1.f2   0.096   0.096   3       3
n1.f3   0       0       0       0
n1.f4   0       0       0       0
n1.f5   28.36   28.36   42      42
n1.f6   0.520   0.520   3       3
n1.f7   0.010   0.010   0.03    0.03
n1.f8   0.141   0.141   0.141   0.141
n2.f1   0.141   0.141   0.400   0.400
n2.f2   0.283   0.283   0.800   0.800
n2.f3   0.318   0.318   1       1
n2.f4   9.326   9.326   9       9
n2.f5   16.47   16.47   28.37   28.37
n2.f6   2.899   2.899   5       5
n2.f7   0.016   0.016   0.03    0.03
n2.f8   3.972   3.972   4       4
n3.f1   5.756   5.756   5       5
n3.f2   3.283   3.283   2       2
n3.f3   0.514   0.514   0.5     0.5
n3.f4   0       0       0       0
n3.f5   0.009   0.009   0.009   0.009
n3.f6   3.952   3.952   5       5
n3.f7   0.017   0.017   0.017   0.017
n3.f8   1.222   1.222   1.5     1.5
n4.f1   69.54   69.54   45      45
n4.f2   19.78   19.78   38      38
n4.f3   2.712   2.712   5       5
n4.f4   12.07   12.07   6       6
n4.f5   4.784   4.784   4.784    4.784
n4.f6   29.10   29.10   60       60
n4.f7   25.10   25.10   30       30
n4.f8   7.110   7.110   8        8
n5.f1   6.558   6.558   8        8
n5.f2   17.08   17.08   15       15
n5.f3   0.642   0.642   0.500    0.500
n5.f4   0.482   0.482   0.500    0.500
n5.f5   0.037   0.037   0.037    0.037
n5.f6   2.272   2.272   10       10
n5.f7   0.146   0.146    0.146   0.146
n5.f8   1.596   1.595   1.5      1.5
n6.f1   31.39   31.39   15       15
n6.f2   36.05   36.05   45       45
n6.f3   31.39   31.39   10       10
n6.f4   9.920   9.920   5        5
n6.f5   1.676   1.676   1.676    1.676
n6.f6   6.556   6.556   20       20
n6.f7   0.981   0.981   1        1
```

```
n6.f8   3.257   3.257    3.257    3.257
;


table AV(n,f,t)
*Availability generation of type f in node n at time t.
*       W2010         S2010    W2020      S2020
        t1            t2       t3         t4
n1.f1   1             1        1          1
n1.f2   1             1        1          1
n1.f3   1             1        1          1
n1.f4   1             1        1          1
n1.f5   1             1        1          1
n1.f6   0.387         0.2      0.387      0.2
n1.f7   0.039         0.202    0.039     0.202
n1.f8   1             1        1          1
n2.f1   1             1        1          1
n2.f2   1             1        1          1
n2.f3   1             1        1          1
n2.f4   1             1        1          1
n2.f5   1             1        1          1
n2.f6   0.387         0.2      0.387      0.2
n2.f7   0.039         0.202    0.039     0.202
n2.f8   1             1         1         1
n3.f1   1             1         1         1
n3.f2   1             1         1         1
n3.f3   1             1         1         1
n3.f4   1             1         1         1
n3.f5   1             1         1         1
n3.f6   0.387         0.2      0.387      0.2
n3.f7   0.039         0.202    0.039     0.202
n3.f8   1             1         1         1
n4.f1   1             1         1         1
n4.f2   1             1         1         1
n4.f3   1             1         1         1
n4.f4   1             1         1         1
n4.f5   1             1         1         1
n4.f6   0.387         0.2      0.387      0.2
n4.f7   0.039         0.202    0.039     0.202
n4.f8   1             1         1         1
n5.f1   1             1         1         1
n5.f2   1             1         1         1
n5.f3   1             1         1         1
n5.f4   1             1         1         1
n5.f5   1             1         1         1
n5.f6   0.387         0.2      0.387      0.2
n5.f7   0.039         0.202    0.039     0.202
n5.f8   1             1         1         1
n6.f1   1             1         1         1
n6.f2   1             1         1         1
n6.f3   1             1         1         1
n6.f4   1             1         1         1
n6.f5   1             1         1         1
n6.f6   0.387         0.2      0.387      0.2
n6.f7   0.039         0.202    0.039     0.202
n6.f8   1             1         1         1
;
```

```
table KAP(n,m,t)
*Invested capacity on line between node n and m in time t, [GW]
*         W2010 S2010     W2020 S2020
          t1       t2      t3       t4
n1.n1   100      100     100      100
n1.n2   3.595    3.595   3.595    3.595
n1.n3   1.000    1.000   1.000    1.000
n1.n4   0        0       0        0
n1.n5   0.700    0.700   0.700    0.700
n1.n6   0        0       0        0
n2.n1   3.595    3.595   3.595    3.595
n2.n2   100      100     100      100
n2.n3   2.040    2.040   2.040    2.040
n2.n4   0.615    0.615   0.615    0.615
n2.n5   0        0       0        0
n2.n6   0        0       0        0
n3.n1   1.000    1.000   1.000    1.000
n3.n2   2.040    2.040   2.040    2.040
n3.n3   100      100     100      100
n3.n4   2.100    2.100   2.100    2.100
n3.n5   0        0       0        0
n3.n6   0        0       0        0
n4.n1   0        0       0        0
n4.n2   0.615    0.615   0.615    0.615
n4.n3   2.100    2.100   2.100    2.100
n4.n4   100      100     100      100
n4.n5   3.850    3.850   3.850    3.850
n4.n6   0        0       0        0
n5.n1   0.700    0.700   0.700    0.700
n5.n2   0        0       0        0
n5.n3   0        0       0        0
n5.n4   3.850    3.850   3.850    3.850
n5.n5   100      100     100      100
n5.n6   1.000    1.000   1.000    1.000
n6.n1   0        0       0        0
n6.n2   0        0       0        0
n6.n3   0        0       0        0
n6.n4   0        0       0        0
n6.n5   0.700    0.700   0.700    0.700
n6.n6   100      100     100      100
;

*EUR/GWH
table CL(n,m)              Investment cost if node 1 is LEADER
*N:1        2          3         4         5         6
*  NO       SE         DK        DE        NL        GB
   n1       n2         n3        n4        n5        n6
n1 10       0.0017     0.0017    0.0017    0.0017    0.0017
n2 0.0017   10         0.0017    0.0017    0.0017    0.0017
n3 0.0017   0.0017     10        0.0017    0.0017    0.0017
n4 0.0017   0.0017     0.0017    10        0.0017    0.0017
n5 0.0017   0.0017     0.0017    0.0017    10        0.0017
n6 0.0017   0.0017     0.0017    10        0.0017    0.0017
;
```

```
Variables
w            Social Welfare in Market
p_t(n,m,t)   Price of transmission from n to m in time t
p_el(n,t)    Price of transmission from n to m in time t
;

Positive Variables
x(n,m)              Level of Investment
q_prod(n,f,t)       Amount of el. produced in n from fuel f at time t
q_sold(n,m,t)       Amount of el. sold from n to m in time t
d(n,t)              Demand in node n at time t
flow(n,m,t)         Flow from n to m in time t
;

equations
eqnWelfare                  The objective function
eqnGenCap(n,f,t)            Generatioon capacity
eqnSold(n,t)                Amount sold from node n to m
eqnFlow(n,m,t)              Flow from node n to m
eqnFlowCap(n,m,t)           Transmission capacity on lines
eqnMCC(n,t)
;

eqnWelfare..
sum((n,t), A(n,t)*d(n,t) - 0.5* B(n,t)*d(n,t)*d(n,t))
- sum((n,f,t), CG(n,f,t)*q_prod(n,f,t))
- sum((n,m), CL(n,m)*x(n,m))  =e= w;

eqnGenCap(n,f,t)..
q_prod(n,f,t) =l= GCAP(n,f,t)*AV(n,f,t);

eqnSold(n,t)..
sum(f, q_prod(n,f,t)) - sum(m, q_sold(n,m,t))  =e= 0;

eqnFlow(n,m,t)..
flow(n,m,t) - q_sold(n,m,t) =e= 0;

eqnFlowCap(n,m,t)..
flow(n,m,t) + flow(m,n,t)  - FCAP(n,m,t) -x(n,m) -x(m,n)  =l= 0;

eqnMCC(n,t)..
d(n,t) - sum(m, q_sold(m,n,t))  =e=  0;


Model it / all  /;

Solve it maximizing w using nlp;
```

D.2 Zonal Transmission Model All Costs Covered

```
Sets
n nodes /n1*n4/
f fuels /f1*f4/
t time /t1*t2/

$ontext
nodes: 1   2   3     4
       NO  DK  DENE  GB

fuels:   1      2       3     4
         Hydro  Solar   Wind  Thermal
$offtext

alias (n,m,mm);

table A(n,t)
*Intercept of inverse demand curve in node n and time t
*  2010   2020
   t1     t2
n1 0.580  0.580
n2 0.580  0.580
n3 0.580  0.580
n4 0.580  0.580
;

table B(n,t)
*Slope of inverse demand curve in node n and time t
*  2010   2020
   t1     t2
n1 0.035  0.034
n2 0.124  0.117
n3 0.008  0.009
n4 0.014  0.014
;


table CG(n,f,t)
*Generation cost for fuel f in node n [EUR/GW]
*       2010   2020
        t1     t2
n1.f1   0.04   0.047
n1.f2   0      0
n1.f3   0      0
n1.f4   0.043  0.052

n2.f1   0.040  0.047
n2.f2   0      0
n2.f3   0      0
n2.f4   0.043  0.052

n3.f1   0.040  0.047
n3.f2   0      0
n3.f3   0      0
n3.f4   0.043  0.052
```

```
n4.f1  0.040  0.047
n4.f2  0      0
n4.f3  0      0
n4.f4  0.043  0.052
;

$ontext
Fuels: 1        2        3        4
       Hydro    Solar    Wind     Thermal
$offtext

table GCAP(n,f,t)
* Generation capacity of fuel f in node n in time t [EUR/GW]
*      2010    2020
       t1      t2
n1.f1  28.37   42
n1.f2  0.01    0.03
n1.f3  0.520   3
n1.f4  0.237   3.141

n2.f1  0.009   0.009
n2.f2  0.017   0.017
n2.f3  3.952   5
n2.f4  10.775  9

n3.f1  4.821  3.037
n3.f2  25.24  30.146
n3.f3  31.343 70
n3.f4  137.57 127.5

n4.f1  1.676  1.676
n4.f2  0.981  1
n4.f3  6.556  20
n4.f4  81.92  68
;


table AV(n,f,t)
* Availability generation of type f in node n at time t.
*      2010   2020
       t1     t2
n1.f1  1      1
n1.f2  0.12   0.12
n1.f3  0.2935 0.2935
n1.f4  1      1
n2.f1  1      1
n2.f2  0.12   0.12
n2.f3  0.2935 0.2935
n2.f4  1      1
n3.f1  1      1
n3.f2  0.12   0.12
n3.f3  0.2935 0.2935
n3.f4  1      1
n4.f1  1      1
n4.f2  0.12   0.12
n4.f3  0.2935 0.2935
n4.f4  1      1
```

```
;

*UNIT: GW
table FCAP(n,m,t)
* Invested capacity on line between node n and m in time t
*       2010      2020
        t1        t2
n1.n1   200       200
n1.n2   1.000     1.000
n1.n3   0.7       0.7
n1.n4   0         0
n2.n1   1.000     1.000
n2.n2   200       200
n2.n3   2.1       2.1
n2.n4   0         0
n3.n1   0.7       0.7
n3.n2   2.1       2.1
n3.n3   200       200
n3.n4   1.000     1.000
n4.n1   0         0
n4.n2   0         0
n4.n3   1.000     1.000
n4.n4   200       200
;

table CL(n,m)
*Investment cost if node 1 is leader [EUR/GWH]
*  NOR     DK       DENE     UK
   n1      n2       n3       n4
n1 10      0.0017   0.0017   0.0017
n2 10      10       0.0017   0.0017
n3 10      10       10       10
n4 10      10       10       10
;


Parameter
K1a /0.06/
K1b /70/
K2a /0.1/
K2b /70/
K3a /0.1/
K3b /70/
K4a /0.1/
K4b /70/
K5a /150/
K5b /0.1/
K7a /200/
K7b /0.1/
;

Variables
w1             Social Welfare in leader zone
p_el(n,t)      Price of electricity
p_t(n,m,t)     Price of transmission
phi(n,t)       Dual of produced = sold constraint
;
```

```
Positive Variables
x(n,m)          GWs invested on line from node n to m in time period t
q_prod(n,f,t)   GWs generated from fuel f at node n in time period t
q_sold(n,m,t)   GWs sold from node n to node m in time period t
d(n,t)          Demand in node n at time t
flow(n,m,t)     Flow on line from node n to node m in time period t
gamma(n,f,t)    Dual of generation capacity
epsilon(n,m,t) Dual of flow capacity
;

Binary variables
r1(n,t)
r2(n,f,t)
r3(n,m,t)
r4(n,m,t)
r5(n,f,t)
r6a(n,f)
r6b(n,f)
r7(n,m,t)
;

equations
eqnWelfare1

ObjDem(n,t)
ObjDem(n,t)
ObjDem(n,t)

ObjProd(n,f,t)
ObjProd2(n,f,t)
ObjProd3(n,f,t)

ObjSold(n,m,t)
ObjSold2(n,m,t)
ObjSold3(n,m,t)

ObjFlow(n,m,t)
ObjFlow2(n,m,t)
ObjFlow3(n,m,t)

GenCap(n,f,t)
GenCap2(n,f,t)
GenCap3(n,f,t)

Sold(n,t)
Flow(n,m,t)

FlowCap(n,m,t)
FlowCap2(n,m,t)
FlowCap3(n,m,t)

MCC(n,t)
;

*Leader's problem: Maximize his own welfare
eqnWelfare1..  w1 =e= sum(t, - 0.5* B('n1',t)*d('n1',t)*d('n1',t))
```

```
                        + sum((t,f), CG('n1',f,t)*q_prod('n1',f,t))
                         - sum((m,t), q_sold('n1',m,t)*p_el(m,t))
                         - sum((m,t), flow('n1',m,t) *p_t('n1',m,t))
                         + sum((n,m), CL(n,m)*x(n,m));

*Market problem: Maximizing market welfare

*KKT: Objective function derived with respect to d(n)

ObjDem(n,t)..  -A(n,t) + B(n,t)*d(n,t)  + p_el(n,t)  =g= 0 ;
ObjDem2(n,t).. -A(n,t) + B(n,t)*d(n,t)  + p_el(n,t) =l= K1a*r1(n,t);
ObjDem3(n,t)..  d(n,t) - K1b*(1-r1(n,t)) =l= 0 ;

*KKT: Objective function derived with respect to q_prod

ObjProd(n,f,t).. CG(n,f,t) + gamma(n,f,t) + phi(n,t)=g= 0;
ObjProd2(n,f,t)..CG(n,f,t) + gamma(n,f,t) + phi(n,t)=l=K2a*r2(n,f,t);
ObjProd3(n,f,t)..q_prod(n,f,t) - K2b*(1-r2(n,f,t)) =l= 0;

*KKT: Objective function derived with respect to q_sold

ObjSold(n,m,t).. -phi(n,t) - p_t(n,m,t) - p_el(m,t)=g= 0;
ObjSold2(n,m,t)..-phi(n,t) - p_t(n,m,t) - p_el(m,t)=l= K3a*r3(n,m,t);
ObjSold3(n,m,t).. q_sold(n,m,t) - K3b*(1-r3(n,m,t)) =l= 0;

*KKT: Objective function derived with respect to flow

ObjFlow(n,m,t).. epsilon(n,m,t) + epsilon(m,n,t)  + p_t(n,m,t) =g= 0;
ObjFlow2(n,m,t)..epsilon(n,m,t) + epsilon(m,n,t)  + p_t(n,m,t) =l= K4a*r4(
    n,m,t);
ObjFlow3(n,m,t).. flow(n,m,t) - K4b*(1-r4(n,m,t)) =l= 0;

*q_prod less than Max Prod

GenCap(n,f,t)..-q_prod(n,f,t) +GCAP(n,f,t)*AV(n,f,t) =g= 0;
GenCap2(n,f,t).-q_prod(n,f,t) +GCAP(n,f,t)*AV(n,f,t)=l=K5a*r5(n,f,t);
GenCap3(n,f,t)..gamma(n,f,t) - K5b*(1-r5(n,f,t)) =l= 0;

*sold = prod

Sold(n,t)..  sum(f, q_prod(n,f,t))- sum(m, q_sold(n,m,t)) =e= 0;

*flow = sold

Flow(n,m,t).. flow(n,m,t) - q_sold(n,m,t) =e= 0 ;

*Flow less than Max Flow

FlowCap(n,m,t)..  -flow(n,m,t) - flow(m,n,t) +  FCAP(n,m,t) + x(n,m)
                + x(m,n)  =g= 0 ;
FlowCap2(n,m,t).. -flow(n,m,t) - flow(m,n,t) +  FCAP(n,m,t) + x(n,m)
               + x(m,n)  =l= K7a*r7(n,m,t) ;
FlowCap3(n,m,t)..  epsilon(n,m,t) - K7b*(1-r7(n,m,t)) =l= 0 ;

*Market clearing

eqnMCC(n,t).. d(n,t) - sum(m, q_sold(m,n,t)) =e= 0;
```

```
model it/all/;


option reslim = 18000;
option MINLP = BARON;
option optcr = 0.009
it.optfile = 1;

solve it using MINLP minimizing w1;
```

D.3 Zonal Transmission Model Bilateral Cost Sharing

```
Sets
n nodes /n1*n4/
f fuels /f1*f4/
t time /t1*t2/

$ontext
nodes: 1   2   3     4
       NO  DK  DENE  GB

fuels:   1      2       3     4
         Hydro  Solar   Wind  Thermal
$offtext

alias (n,m,mm);

table A(n,t)         Intercept of inverse demand curve in node n and time
    t
*  2010   2020
   t1     t2
n1 0.580  0.580
n2 0.580  0.580
n3 0.580  0.580
n4 0.580  0.580
;

table B(n,t)          Slope of inverse demand curve in node n and time t
*  2010   2020
   t1     t2
n1 0.035  0.034
n2 0.124  0.117
n3 0.008  0.009
n4 0.014  0.014
;

*UNIT: EUR/GW
table CG(n,f,t)          Generation cost for fuel f in node n (Equal for
     all time periods)
*       2010   2020
        t1     t2
n1.f1   0.04   0.047
n1.f2   0      0
n1.f3   0      0
n1.f4   0.043  0.052

n2.f1   0.040  0.047
n2.f2   0      0
n2.f3   0      0
n2.f4   0.043  0.052

n3.f1   0.040  0.047
n3.f2   0      0
n3.f3   0      0
n3.f4   0.043  0.052
```

```
n4.f1  0.040  0.047
n4.f2  0      0
n4.f3  0      0
n4.f4  0.043  0.052
;

$ontext
Unit: GW
Fuels: 1        2        3        4
       Hydro    Solar    Wind    Thermal
$offtext

table GCAP(n,f,t)    Generation capacity of fuel f in node n in time t. (
    Equal for all time periods)
*  Winter Summer Winter Summer
       t1      t2
n1.f1  28.37   42
n1.f2  0.01    0.03
n1.f3  0.520   3
n1.f4  0.237   3.141

n2.f1  0.009   0.009
n2.f2  0.017   0.017
n2.f3  3.952   5
n2.f4  10.775  9

n3.f1  4.821  3.037
n3.f2  25.24  30.146
n3.f3  31.343 70
n3.f4  137.57 127.5

n4.f1  1.676  1.676
n4.f2  0.981  1
n4.f3  6.556  20
n4.f4  81.92  68
;


table AV(n,f,t)  Availability generation of type f in node n at time t.
*      2010   2020
       t1     t2
n1.f1  1      1
n1.f2  0.12   0.12
n1.f3  0.2935 0.2935
n1.f4  1      1
n2.f1  1      1
n2.f2  0.12   0.12
n2.f3  0.2935 0.2935
n2.f4  1      1
n3.f1  1      1
n3.f2  0.12   0.12
n3.f3  0.2935 0.2935
n3.f4  1      1
n4.f1  1      1
n4.f2  0.12   0.12
n4.f3  0.2935 0.2935
```

```
n4.f4  1      1
;

*UNIT: GW
table FCAP(n,m,t)      Invested capacity on line between node n and m in
    time t
*      2010     2020
       t1       t2
n1.n1  200      200
n1.n2  1.000    1.000
n1.n3  0.7      0.7
n1.n4  0        0
n2.n1  1.000    1.000
n2.n2  200      200
n2.n3  2.1      2.1
n2.n4  0        0
n3.n1  0.7      0.7
n3.n2  2.1      2.1
n3.n3  200      200
n3.n4  1.000    1.000
n4.n1  0        0
n4.n2  0        0
n4.n3  1.000    1.000
n4.n4  200      200
;

*UNIT: EUR/GWH
table CL(n,m)              Investment cost if node 1 is LEADER
*  NOR     DK       DENE    UK
   n1      n2       n3      n4
n1 10      0.0017   0.0017  0.0017
n2 10      10       0.0017  0.0017
n3 10      10       10      10
n4 10      10       10      10
;


Parameter
K1a /0.06/
K1b /70/
K2a /1/
K2b /70/
K3a /1/
K3b /70/
K4a /1/
K4b /70/
K5a /150/
K5b /1/
K6a /10/
K6b /100/
K7a /200/
K7b /0.1/
;

Variables
w1
p_el(n,t)             Dual of demand constraint
```

```
p_t(n,m,t)
phi(n,t)
;

Positive Variables
x(n,m)                    MWs invested on line between node n to node m in
    time period t
q_prod(n,f,t)             MWs generated from fuel f at node n in time period t
q_sold(n,m,t)             MWs sold from node n to node m in time period t
d(n,t)                    Demand in node n at time t
flow(n,m,t)               Flow on line from node n to node m in time period t
gamma(n,f,t)
epsilon(n,m,t)
;

Binary variables
r1(n,t)
r2(n,f,t)
r3(n,m,t)
r4(n,m,t)
r5(n,f,t)
r6(n,m)
r7(n,m,t)
;

*Fixing variables in order to speed up solution
r6.fx(n,m)$(ord(n) > ord(m)) = 1;

equations
eqnWelfare1
eqnX(n,m)
eqnObjDemand(n,t)
eqnObjDemand2(n,t)
eqnObjDemand3(n,t)

eqnObjProd(n,f,t)
eqnObjProd2(n,f,t)
eqnObjProd3(n,f,t)

eqnObjSold(n,m,t)
eqnObjSold2(n,m,t)
eqnObjSold3(n,m,t)

eqnObjFlow(n,m,t)
eqnObjFlow2(n,m,t)
eqnObjFlow3(n,m,t)

eqnObjX(n,m)
eqnObjX2(n,m)
eqnObjX3(n,m)

eqnGenCap(n,f,t)
eqnGenCap2(n,f,t)
eqnGenCap3(n,f,t)

eqnSold(n,t)
```

```
eqnFlow(n,m,t)

eqnFlowCap(n,m,t)
eqnFlowCap2(n,m,t)
eqnFlowCap3(n,m,t)

eqnMCC(n,t)
;

*Leader's problem: Maximize his own welfare
eqnWelfare1..  w1 =e= sum(t, - 0.5* B('n1',t)*d('n1',t)*d('n1',t))
                    + sum((t,f), CG('n1',f,t)*q_prod('n1',f,t))
                    - sum((m,t), q_sold('n1',m,t)*p_el(m,t))
                    - sum((m,t), flow('n1',m,t) *p_t('n1',m,t))
                    + 0.5*sum((m), CL('n1',m)*x('n1',m));

eqnX(n,m).. x('n1',m) =l= 100;
*Market problem: Maximizing market welfare

*KKT: Objective function derived with respect to d(n)
eqnObjDemand(n,t)..  -A(n,t) + B(n,t)*d(n,t)  + p_el(n,t)  =g= 0 ;
eqnObjDemand2(n,t).. -A(n,t) + B(n,t)*d(n,t)  + p_el(n,t) =l= K1a*r1(n,t);
eqnObjDemand3(n,t)..  d(n,t) - K1b*(1-r1(n,t)) =l= 0 ;

*KKT: Objective function derived with respect to q_prod
eqnObjProd(n,f,t)..  CG(n,f,t) + gamma(n,f,t) + phi(n,t)   =g= 0;
eqnObjProd2(n,f,t).. CG(n,f,t) + gamma(n,f,t) + phi(n,t)   =l= K2a*r2(n,f,t);
eqnObjProd3(n,f,t).. q_prod(n,f,t) - K2b*(1-r2(n,f,t)) =l= 0;

*KKT: Objective function derived with respect to q_sold
eqnObjSold(n,m,t)..  -phi(n,t) - p_t(n,m,t) - p_el(m,t) =g= 0;
eqnObjSold2(n,m,t).. -phi(n,t) - p_t(n,m,t) - p_el(m,t) =l= K3a*r3(n,m,t);
eqnObjSold3(n,m,t).. q_sold(n,m,t) - K3b*(1-r3(n,m,t)) =l= 0;

*KKT: Objective function derived with respect to flow
eqnObjFlow(n,m,t).. epsilon(n,m,t) + epsilon(m,n,t) + p_t(n,m,t) =g= 0;
eqnObjFlow2(n,m,t)..epsilon(n,m,t)+ epsilon(m,n,t) + p_t(n,m,t) =l= K4a*r4(n,m,t);
eqnObjFlow3(n,m,t).. flow(n,m,t) - K4b*(1-r4(n,m,t)) =l= 0;

*KKT: Objective function derived with respect to investements x
eqnObjX(n,m)..  0.5*CL(n,m) - sum(t, epsilon(n,m,t)) -sum(t, epsilon(m,n,t))  =g= 0;
eqnObjX2(n,m).. 0.5*CL(n,m) - sum(t, epsilon(n,m,t)) -sum(t, epsilon(m,n,t)) =l= K6a*r6(n,m);
eqnObjX3(n,m)$(ord(n) > 1).. x(n,m)  =l= K6b*(1-r6(n,m));


*q_prod less than Max Prod
eqnGenCap(n,f,t).. -q_prod(n,f,t) + GCAP(n,f,t)*AV(n,f,t) =g= 0;
eqnGenCap2(n,f,t)..-q_prod(n,f,t) + GCAP(n,f,t)*AV(n,f,t) =l= K5a*r5(n,f,t);
eqnGenCap3(n,f,t)..  gamma(n,f,t) - K5b*(1-r5(n,f,t)) =l= 0;

*sold = prod
eqnSold(n,t)..  sum(f, q_prod(n,f,t))- sum(m, q_sold(n,m,t)) =e= 0;
```

```
*flow = sold
eqnFlow(n,m,t).. flow(n,m,t) - q_sold(n,m,t) =e= 0 ;

*Flow less than Max Flow
eqnFlowCap(n,m,t)..  -flow(n,m,t) - flow(m,n,t) +  FCAP(n,m,t) + x(n,m) +
    x(m,n)  =g= 0 ;
eqnFlowCap2(n,m,t).. -flow(n,m,t) - flow(m,n,t) +  FCAP(n,m,t) + x(n,m) +
    x(m,n) =l= K7a*r7(n,m,t) ;
eqnFlowCap3(n,m,t)..  epsilon(n,m,t) - K7b*(1-r7(n,m,t)) =l= 0 ;

*Market clearing
eqnMCC(n,t).. d(n,t) - sum(m, q_sold(m,n,t)) =e= 0;

model it /all/;

option reslim = 28800;
option MINLP = BARON;
option optcr = 0.00009;
it.optfile = 1;

solve it using MINLP minimizing w1;
```

Appendix E

Content on Enclosed CD

1. Excel spreadsheet with input data
2. GAMS code for the Supranational Planning Model
3. GAMS code for the Zonal Planning Model
4. GAMS code for the Zonal Planning Model and Bilateral Cost