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Norwegian Hydropower and large scale Wind Generation in the North Sea

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Problem description

Several HVDC links between Norway and Great Britain have been proposed. One of these links is passing by the planned offshore wind farm Dogger Bank. This renders it possible to utilize the flexibility between Norwegian hydro power, wind generation at Dogger Bank and the Great Britain power system. Calculations and simulations for different cable connection sites should be carried out using the EMPS-model. Additionally, price formation in the different markets and issues related to transmission constraint in Western Norway and Great Britain are important factors.

The following tasks are included:

- Create a model of the present power system in Great Britain.
- Simulate and discuss different cable alternatives from Norway to Scotland and Southern England with the present power system.
- Create a model for the Great Britain power system including Dogger Bank in 2020. Simulate and discuss different cable alternatives from Great Britain and Dogger Bank to Norway.
- Evaluate the cable's impact on the power systems in Norway and Great Britain.

Assignment given: 17. January 2011

Supervisor: Gerard Doorman, ELKRAFT

Preface

This thesis is written as a part of the master's degree in Energy and Environmental Engineering at the Norwegian University of Science and Technology. The work with this thesis is carried out during the spring semester 2011.

The subject at hand is comprehensive both from a technical and an economical point of view. It has therefore not been possible to give all the answers, but I hope that the present work will contribute to further work on the subject.

I would like to express my gratitude to my supervisor, Dr. Gerard Doorman for providing assistance for the completion of this thesis. Thanks should also be expressed to Phd Candidate Stefan Jaehnert and Dr.-Ing. Steve Völler whose help have been of great importance. Last but not least, I would like to express my thanks to my fellow students for providing me with knowledge and perspective on the subjects discussed in this thesis.

Trondheim, July 2011

Abstract

The addressed issue for this report is the making of a model, which represents the power system in Great Britain. This model is connected to an already existing model of Northern Europe in order to study how the present power systems are affected by eventual connections between Great Britain and Norway and the profitability of these. A model for 2020 is also created in order to study how increased wind generation are affecting such cables.

Electricity trading in Norway is normally done through the Nord Pool exchange which also covers the other Nordic countries. Most of the electricity is traded in the Elspot market where hourly contracts are traded daily for physical delivery in the next day's 24–hour period. The price for the volumes traded is based on the intersection between the supply and demand curves. Participants in Norway are normally trading their entire volumes at the exchange. This is distinct from trading in Great Britain where the base load and the 'shape' normally are traded separately. Electricity trading in Great Britain is based on bilateral agreements which allow direct contracting between counterparts. Each transaction is made independently between the parties involved, giving the customers an opportunity to negotiate the best price from suppliers and generators without being constrained by any official price.

Models for both a 2010 and a 2020 scenario of the Great Britain power system are created in the EMPS-model. The EMPS model is a market simulator which optimizes the utilization of a hydro-thermal power system based on stochastic supply and demand. Great Britain is divided into four areas in both scenarios. Each area has defined transfer capacities to other connected areas while the transfer capacity within each area is unlimited. These areas are therefore defined in such a way that boundaries with insufficient transfer capabilities in the real system are located at the boundary between two areas in the model. Coal, gas, bio and oil fired plants are represented individually in the model while nuclear, wind, small scale CHP, hydro and pumped storage capacities are aggregated for each area. Meaning that there is only one aggregated nuclear plant, one aggregated wind farm etc. in each area. An area also has a given demand which varies throughout the week and year. Price calculations in the model are based on the intersection between the supply curve and the demand curve. Pricing in

the model is therefore more representative for the way of pricing in Norway than in Great Britain.

For the 2010 scenario, three different cable alternatives are simulated. Two of these cases are equal except for the landing area of the cables in Great Britain. One cable is connected to Southern England while the other is connected to Northern Scotland. For the third case, the assumptions are similar to the other cases except for an equalization of the gas price in Europe. The landing area for the cable in this case is Southern England. All three cable alternatives returns a fair-sized congestion rent, but the congestion rent is not sufficient to cover the investment cost for any of the discussed cables based on the defined assumptions. Additionally, the cables result in large grid constraints across the boundary between the landing area in Norway and the other Norwegian areas connected to this area. Increased constraints are also an issue for the cable connected to Northern Scotland.

Towards 2020, installed wind capacity is expected to rise considerably. This also includes offshore wind farms such as Dogger Bank. A cable from Norway could therefore be connected to Dogger Bank and utilize spare capacity on the cable from Dogger Bank to Great Britain. Three different cables are discussed for the 2020 scenario. The first case is a cable from Norway to Southern England and the second and third case are cables from Norway to Dogger Bank. All three cables have the same transfer capacity. The difference between the two cables connected to Dogger Bank is the transfer capacity from Dogger Bank to Great Britain. The second case has a transfer capacity towards Britain which equalizes the installed wind capacity at Dogger Bank. For the third case, the sum of both the cable towards Norway and the one towards Britain equalizes the installed capacity at Dogger Bank. As for the cases in the 2010 scenario, none of these cable alternatives generate a congestion rent which is sufficient to make the cable profitable based on the defined assumptions.

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1 Introduction

Several alternatives for subsea cables connecting Great Britain have been proposed the last years. Currently two consortiums have submitted applications for concession for such a cable. Connecting the Norwegian and the Great Britain power systems is assumed to gain both the cable owner and the participants in the respective systems.

The Norwegian power system is dominated by hydropower. Hydro power plants are both cheap and fast to regulate. This normally results in a relative constant price throughout the day. A system with such a large share of hydropower is vulnerable due to the dependency of inflow. The system is therefore dependent on transfer capacity to surrounding areas with thermal capacity. Norway has an energy balance in years with normal inflow, meaning that the inflow equals the volume of water used for generation to cover demand. Net export is therefore normally present in years with inflow higher than normal while years with inflow less than normal usually have a net import. Prices might therefore have relatively large variations from season to season and from year to year.

In Great Britain, the power system is dominated by thermal generation. The cost of generation depends on the cost of fuel which normally is relative constant throughout a year. Cost of regulations on the other hand is quite costly due to the energy loss related to changes in output or start-up of additional units. Prices may therefore vary quite a lot during the day. The increased priority of wind generation is expected to increase the need for regulation.

The power systems in Norway and Great Britain are in many ways complimentary systems. Prices in Norway are relative stable during the day while they are fluctuating in Great Britain. Seasonal and yearly price variations are normally larger in Norway than in Great Britain. These facts combined indicate that there is an arbitrage potential between the two countries which can be utilized by a cable.

Part I Power markets

2 Power markets in the Nord Pool area and Great Britain

Prior to 1989, both the Scandinavian and the Great Britain energy systems were dominated by public ownership. Most of the generation capacity and the transmission grid in England were owned by the State. Scandinavia had a more decentralized ownership divided by the State, counties and municipalities[1]. England & Wales were pioneers in European restructuring which came with the Electricity Act of 1989. Norway followed a year later with the Energy Act of 1990 which formed the basis for deregulation in the other Nordic countries. These restructuring processes were intended to make the electricity markets more competitive and efficient. In order to reach these goals, England & Wales had to split large publicly owned companies into smaller ones. By privatizing these companies, a more distributed ownership of the power system was obtained. This goal was reached through privatization of these smaller companies. Other arguments for restructuring were reduction of the price discrimination between customers and that the market price should reflect the marginal cost.

2.1 The Nord Pool market

Before restructuring in Norway, the electrical prices were based on cost recovery [1]. This gave the power producers an incentive to mix the cost of expensive new developments with cheaper existing plants in such a way that the consumers got a considerably higher price than the marginal cost. This way of pricing, resulted in development of more generation capacity than required.

Nord Pool was established in 1993 as an exchange for the Norwegian electricity market. The exchange was extended to include Sweden in 1996, Finland and Western Denmark in 1998, Eastern Denmark in 2000 and Estonia in 2010.

In 2002, Nord Pool's spot market activities were organized in a separate company, Nord Pool Spot AS [2]. This company was initially owned by the transmission system operators in the Nordic exchange area and Nord Pool ASA. These TSO's are Statnett, Svenska Kraftnät, Fingrid Oyj and Energinet.dk which are located in Norway, Sweden, Finland and Denmark respectively. Nord Pool Clearing ASA, Nord Pool Consulting AS and the international products from Nord Pool ASA were acquired by NASDAQ OMX and merged into NASDAQ OMC Commodities AS in 2008 [3]. Presently, Nord Pool Spot are offering trade in the Elspot and the Elbas market, while NASDAQ OMX Commodities offers trade with Futures, Forwards, CfDs (Contract for Differences) and Options within the Nordic area. The balancing markets are organized by the TSOs in their respective countries. An hour by hour overview of the Elspot, Elbas and Balancing Market is given in Figure 2.1.

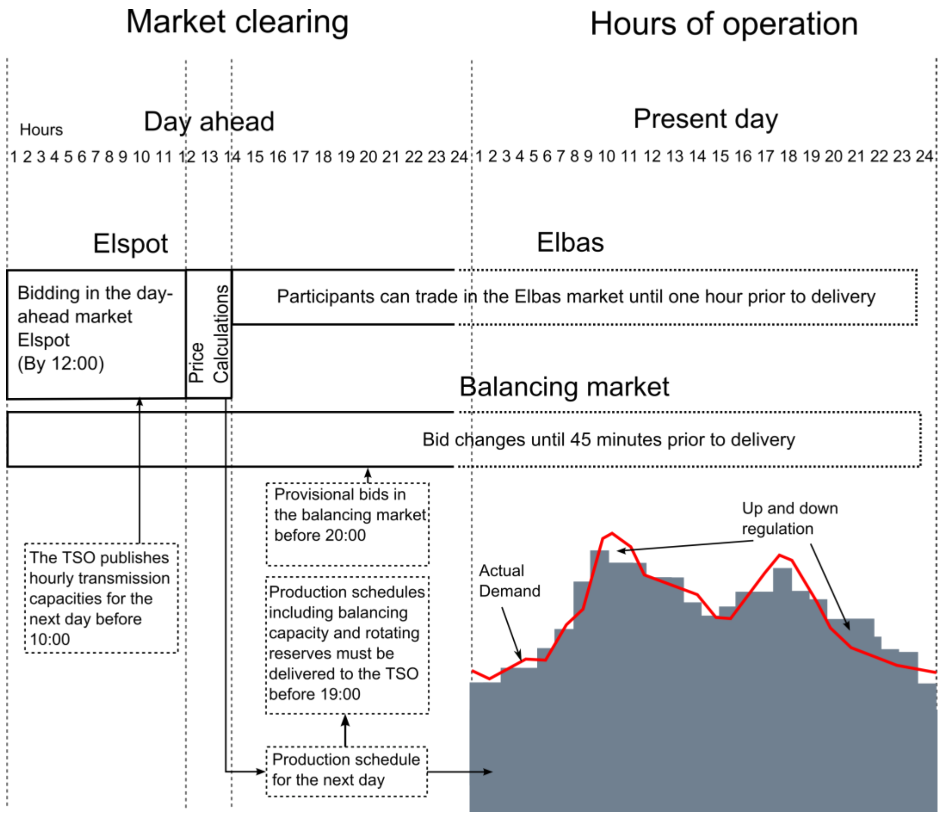

Figure 2.1: Hour by hour overview of the Elspot, Elbas and Balancing Market

2.1.1 Elspot

Elspot, which is organized by Nord Pool Spot, is a market where hourly contracts are traded daily for physical delivery in the next day's 24-hour period [4]. The price calculations are based on the intersection between the market's supply curve and demand curve. These curves consist of bids and offers from all market participants. This trading method is referred to as auction trading, simultaneous price setting or equilibrium point trading. Elspot's share of the Nordic electricity consumption increased to 72 % in 2009, compared to 70 % in the preceding year [5]. Bidding in the Elspot market is performed through three types of bids. These are hourly bids, block bids and flexible hourly bids [6]. Bidding volumes are stated in MW per hour, while bidding purchases are designated as positive numbers and sales as negative numbers. Bids are ranked in merit order into a supply curve and a demand curve and the intersection between these curves determines the spot price. A short description of the Elspot bid types are given in Appendix A.

2.1.2 The Elbas market

Elbas is a continuous intra-day market which covers the Nordic countries, Germany and Estonia [7]. Participants in the day-ahead market can use the Elbas market to make adjustments until one hour prior to delivery. Participants, which have imbalances after the trades in the day-ahead market are final, may solve them by using this market. The Elbas market is therefore an alternative to the balancing market. It should also be noted that the price is known one hour prior to delivery in Elbas, while it is calculated afterwards in the balancing market. An adjustment of eventual imbalances in Elbas reduces therefore the economic risk, while unknown prices with high volatility in the balancing market may lead to a greater economic risk.

2.1.3 Balancing market

The Nordic balancing markets are operated by each country's respective TSO since they additionally of being 'System Operator' also have the role as 'Settlement Responsible' [8]. As a result of this, each country have a set of different national rules and routines. The greater part of these rules and routines are similar, but each country has their own differences. These differences represent barriers for entry and quite few Nordic retailers operate in more than one of the Nordic countries. In order to solve these obstacles, the Nordic TSOs have composed a proposition for a common Nordic balancing settlement. This proposition was sent out for consultation in February 2011 to receive feedback from relevant stakeholders, i.e. retailers, grid companies, industry associations, balance responsible parties, regulators and Nord Pool Spot [8].

Since the main features of the Nordic balancing markets are similar, only a description of the Norwegian market is discussed. The Norwegian TSO, Statnett, is responsible for ensuring that the fed in power equals the outlet [9]. Statnett is achieving this balance by instructing participants in the market to increase or decrease generation. Since Norway, presently, is divided in five price areas, an individual balance for each area has to be achieved. Imbalances are mainly solved by bids for up and down regulation in the balancing market.

A bid in the balancing market consists of a specific volume for one or several hours, with a certain price [10]. Participants can submit different bids for up and down regulation for each hour. These bids are linked to the location of the bidder's power plant or consumption area. The price limit is set to 5000 Euro pr. MW/h and the submitted capacity has to be constant for one hour. Bid volumes cannot be less than 25 MW. However, the limit for small participants with less installed capacity is set to 10 MW. Provisional bids for the next 24-hour period shall be delivered to the TSO before 20:00. New bids or corrections of previous enrolments must be reported to Statnett not less than 45 minutes prior to the hour of operation.

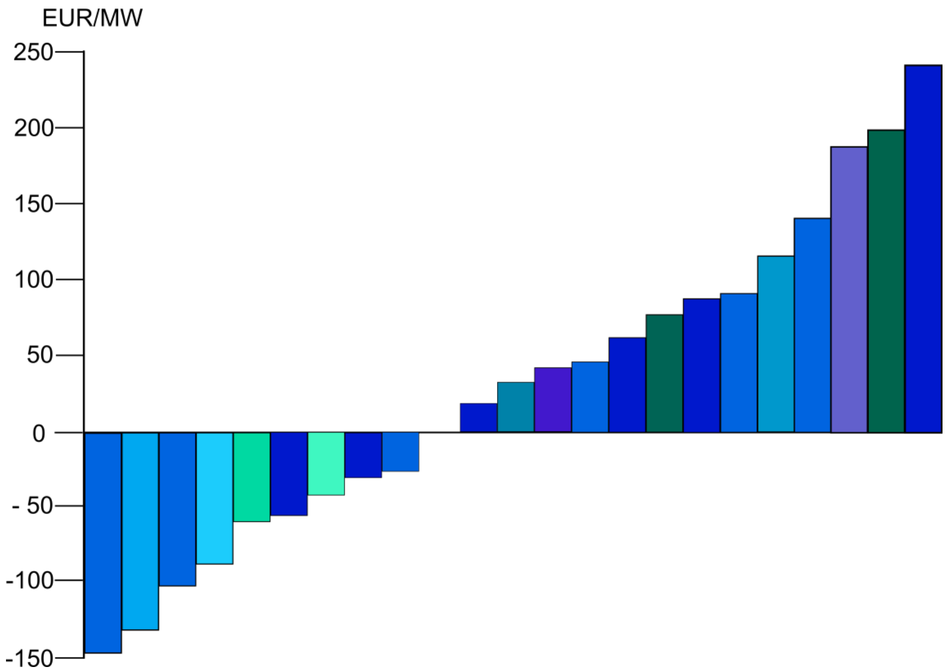

Figure 2.2: Bids for up and down regulation in the balancing market.

The bids for each hour are ranked in merit order as shown in Figure 2.2. Normally the lowest bids are used first if there is a need for regulation. This is not the case if the bidden capacity and the need for regulation are located in separate areas with limited transmission capacity in between. In such cases, the TSO is forced to use a bid from that particular area even though it is not the lowest bid. Since the amount of utilized capacity is unknown until the hour of operation, the prices for regulation in each area are calculated afterwards. Bids from other Nordic countries and areas outside the Nord Pool area are utilized in the same manner as bids from participants within Norway.

2.1.4 Generation mix

The energy system in Norway is mainly based on hydroelectric power production. In 2009, 96 % of the electricity was produced by hydro power, 3 % by thermal and 1 % from wind [11]. Hydro power production is depending on the precipitation in the inflow area which varies through the seasons and from year to year. Since most of the precipitation during the winter season is stored as snow, water has to be stored in reservoirs during the filling season for winter use. These reservoirs have a total capacity of approximately 85 TWh and they reduces the vulnerability of the system for seasonal and yearly inflow variations [12]. The average annual inflow volume in Norway is 123.4 TWh. There are still considerable annual variations and the year with least and the one with most inflow, for the last decade, had an inflow of 106.1 TWh and 142.3 TWh respectively [13]. These fluctuations from year to year are to some extent damped by the reservoirs, but several dry years in a row may pose a threat to the system's ability to deliver the required amount of energy. If the Norwegian power system were insulated, the coherence between supply and demand for a wet and a dry year would be similar to the sketch in Figure 2.3.

A dry year leads to lack of water in the reservoirs, which shifts the supply curve to the left. This results in a new cross point between supply and demand, which indicates higher prices P_D and lower consumption X_D. The opposite is valid for a wet year. The supply curve is shifted to the right, which results in lower prices P_W and higher consumption X_W.

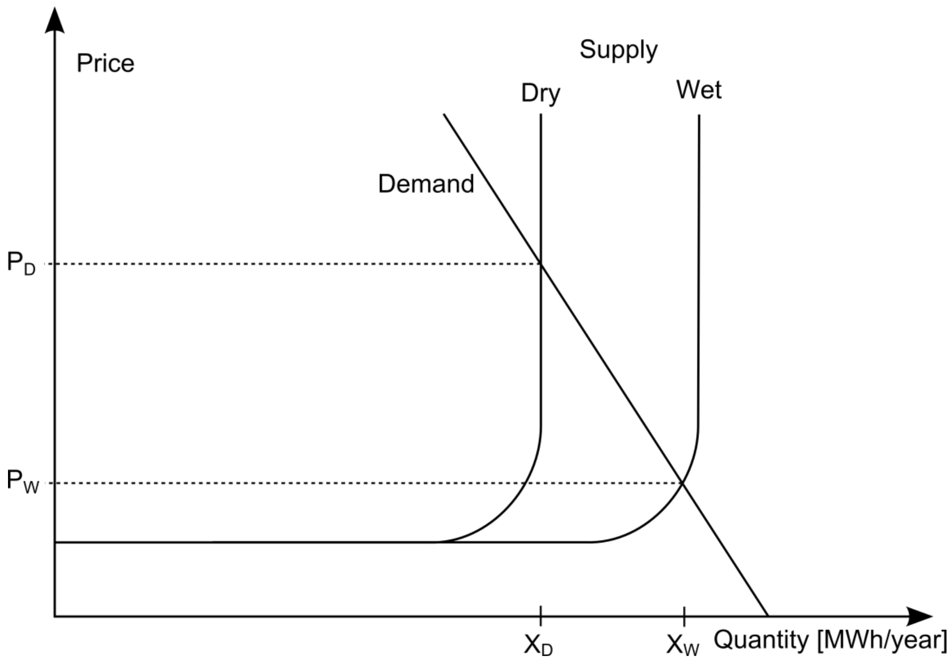

Figure 2.3: Supply and demand, for a dry and a wet year with Norway cut off from the outside world

Norway as an insulated power system is only a fictitious example. In reality, transmission lines and cables are connecting Norway to the other Nordic countries, Russia and The Netherlands. These connections are therefore reducing the precipitations impact on electricity prices in Norway. A dry year would normally lead to net import to Norway, while a wet year normally would result in net export. Germany, Poland and Estonia are also connected to the Nordic power system through submarine cables or transmission lines. An overview of total exchange capacities within the Nordic area and exchange capacities to the surrounding countries are given in Figure 2.4.

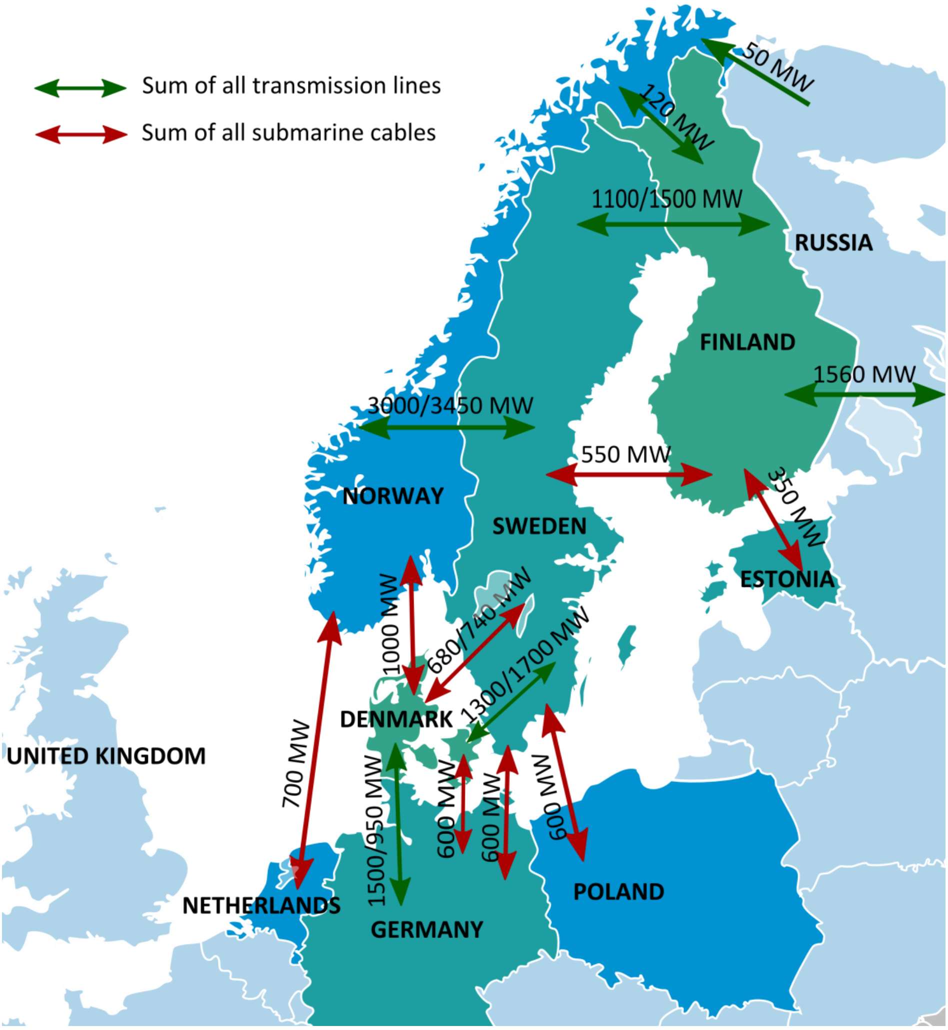

Figure 2.4: Nordic transmission capacities. Based on [14]

Even though Norway is dominated by hydro power, this is not the case for the rest of the countries within the Nord Pool area. A considerable part of the electricity produced in Sweden, Finland and Denmark is based on thermal production and to some extent wind. Supply and demand curves for the Nord Pool area would be similar to the curves in Figure 2.5.

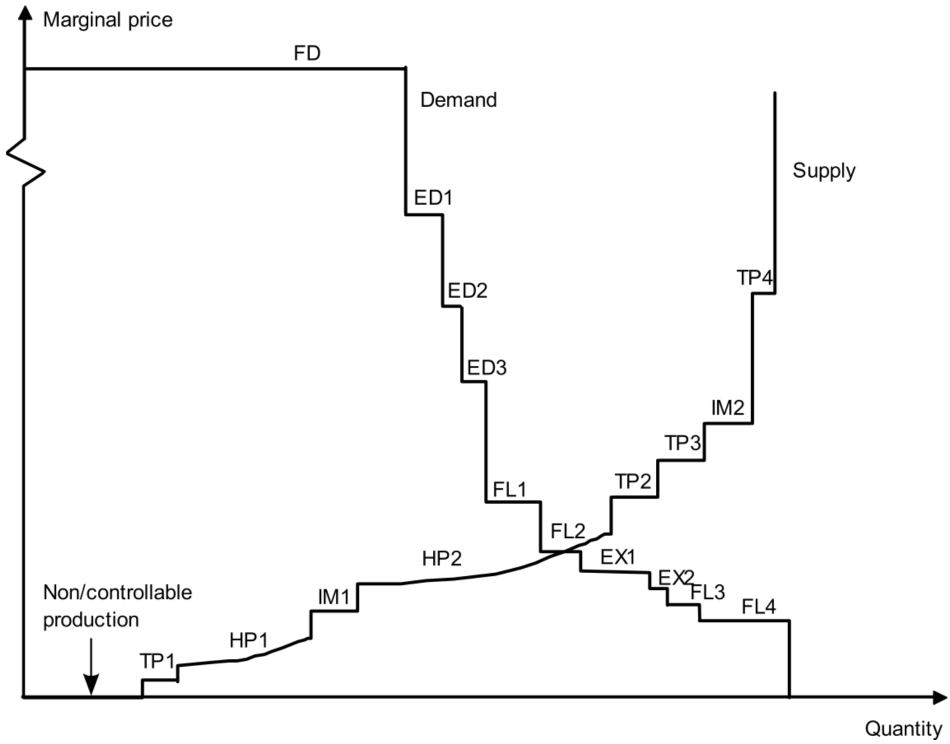

Figure 2.5: Example of supply and demand curves in the Elspot market [15]

The non-controllable production in the supply curve may for instance represent wind power or run of river plants. TP is thermal production, HP is hydro production and IM is imports from surrounding countries. The demand curve is given by a firm demand FD, a number of discrete levels ED representing firm demand which is affected by the price, flexible loads FL and export EX.

The price cross gives the system price, which is the price in the entire Nord Pool area assuming that there are no grid constrains. Sweden, Finland, Estonia, Western Denmark and Eastern Denmark constitute one separate price area each. Norway is subdivided into five geographical areas. The Norwegian price areas are a result of constraints in the transmission system. Changes in the location of the constraints, for example due to improvements in the grid, may results in changes of the price areas. Constraints may lead to large price variations between the areas. Figure 2.6 gives an overview of the price areas and prices within the Nord Pool area for two specific days.

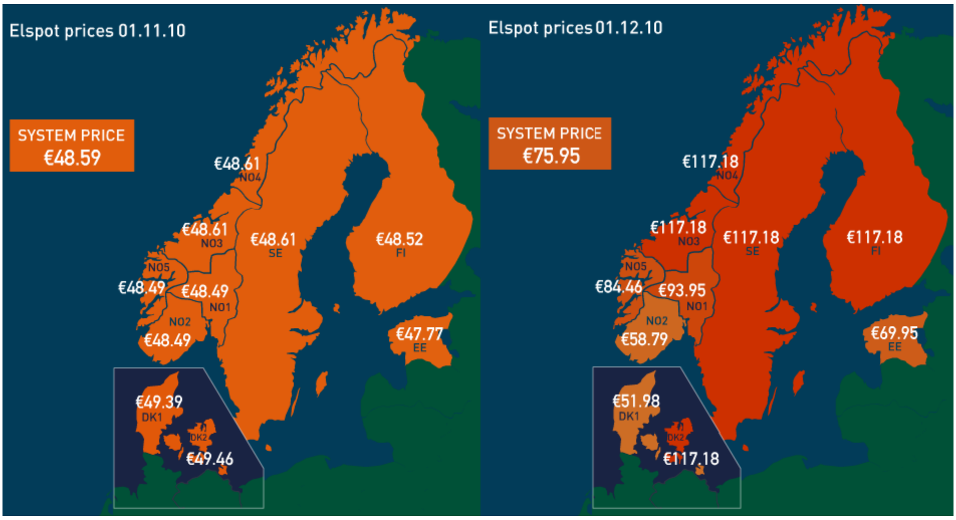

Figure 2.6: Price areas and prices 1. November and 1. December 2010 for the Nord Pool area [16]

2.2 Great Britain power market

The current arrangement for the power system in Great Britain is the British Electricity Trading and Transmission Arrangement (BETTA). A short description of the previous arrangements is given in Appendix B.

2.2.1 BETTA market structure

Trading in BETTA can be broken down to three sequential phases, forward trading, day-ahead trading and on-the-day trading. An overview of the BETTA market structure is illustrated in Figure 2.7. This new arrangement introduced a voluntary bilateral market including power exchanges.

Trade between suppliers and generators take place in the wholesale market. This is a market for sale and purchase of electricity, where suppliers are trading with generators in order to meet the demand of their customers [17]. This market allows unrestricted bilateral contract trading, resulting in a competitive market since the suppliers can trade with a generating company of their choice. Suppliers buy electricity at a price they are willing to pay while generators sell electricity at a price they are willing to receive for it. The final price is then reached through negotiation or exchange trading. Trading between counterparts normally takes a relative standardised form. An amount of energy, with a certain price per unit, is agreed for delivery in a specified period of time in the future. These contracts can be struck well ahead of delivery, spanning from years to an hour ahead of delivery when the contracts are frozen. Most of the electricity traded long time in advance is meant to cover the minimum amount needed to match demand. These volumes are often referred to as 'baseload' and are usually the same amount of energy for each half-hour, day in day out. Suppliers tend to use power exchanges to add 'shape' to their baseload volumes in order to meet the variations in demand on a specific day. This tuning is normally carried out closer to delivery since the conditions at the point of delivery are better known then. This includes for instance weather conditions and television schedules. Even though most of the electricity is traded for longer periods, these periods are put together by half hour 'chunks'. These chunks are referred to as settlement periods and each day is split into 48 such periods. Settlement period 1 is equivalent to the time period from 00:00 to 00:30, while 00:30 to 01:00 is settlement period 2 etc [17]. Every settlement period is settled individually isolated from the period before and the one after. Participants in the market are therefore allowed to strike deals until one hour prior to the settlement period. This deadline is referred to as 'gate closure'.

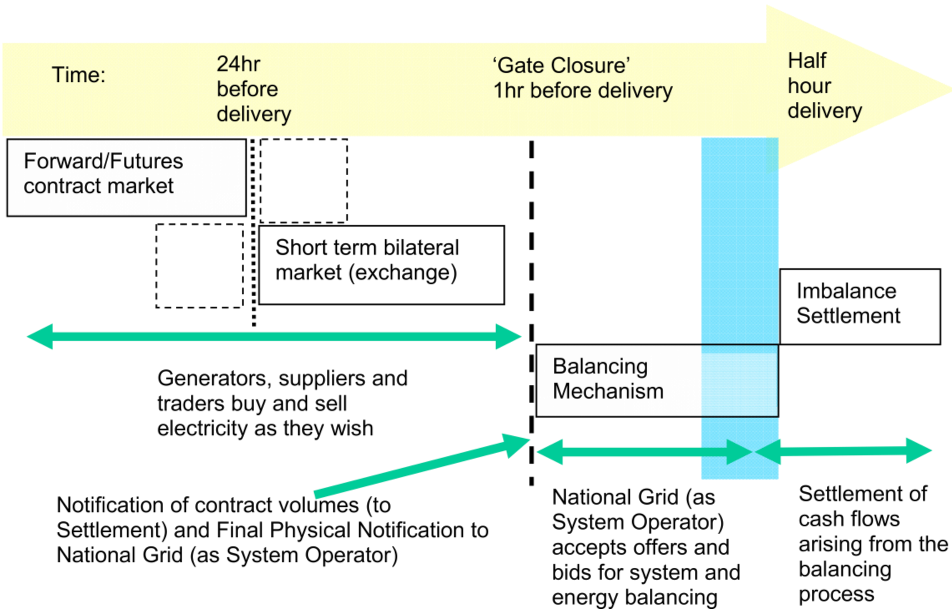

Figure 2.7: Overview of the BETTA market structure [18]

2.2.2 Bilateral agreements

A bilateral market allows direct contracting between counterparts. Each transaction is made independently between the parties involved [19]. This gives the customers opportunity to negotiate the best energy price from suppliers and generators without being constrained by any official price. Buyers and sellers will resort to different forms of bilateral trading based on the quantities to be traded and the time available [20].

Customized long-term contracts are negotiated privately resulting in more flexible terms to meet the needs and objectives of both parties. Such contracts usually involve the sale of large amounts of power over long periods of time, stretching from several months to several years. These contracts are normally depending on a certain duration in order to make them profitable due to the large transaction cost associated with the negotiation of these contracts [20].

Trading over the counter involve smaller amounts of energy. This is to be delivered according to a standard profile, which is a standardised definition of how much energy should be delivered during different periods of the day and week. Transaction cost for OTC trading is much lower and it is normally used by consumers and producers to tune their position as delivery time approaches [20].

Electronic trading allows participants to enter offers to buy energy and bids to sell energy directly in a computerised marketplace. Quantities and prices submitted for the bids are accessible to all participants, but the identity of the party that submitted each bid and offer is not made public. When a bid is entered by a participant, the software running the exchange, checks for a matching offer for the given period of delivery. If a matching offer with a higher or equal price of the bid is found, a deal is automatically struck and the price and quantity are displayed for all participants to see. If there is no match for the bid, the bid is added to the list of outstanding bids. These bids are matched with eventual new offers until the bid is withdrawn by the bidder or it lapses because the market closes for the particular period. A similar matching is carried out for new offers entering the system. This way of trading is cheap and very fast, allowing participants to fine-tune their positions minutes or even seconds before the market closes prior to the delivery period [20].

2.2.3 Balancing mechanism

The balancing settlement in Great Britain is regulated by the Balance and Settlement Code (BSC), which is part of the BETTA regulations [9]. Ofgem is the responsible authority to oversee theses regulation. National Grid is the system operator and their subsidiary, Elexon, is responsible for most of the administrative aspects regarding the BSC. National Grid is therefore responsible for the physical balance in the system, while Elexon among others is responsible for metering data and the settlement.

Participants operating in the wholesale market are not obligated to have a balance between their actual position and their contracted position in the hour of operation. Even though the balancing settlement is constructed in order to give the participants incentives to balance their position, it is inevitable that imbalances occur. This is due to the unpredictable variations in the demand, which is a dynamic respond to external factors and therefore is not fixed ahead of time [17]. Nevertheless, participants are obligated to submit their initial positions for every hour of operation for the following day to the system operator, National Grid, by 11 am the day prior to delivery [9]. Initial positions are stated in an Initial Physical Notification (IPN). These positions are then continuously updated until gate closure when the participants must submit a Final Physical Notification (FPN), which state their final positions.

Information from both the IPN and the FPN is used by National Grid to balance the system. Balancing actions/services fall into three categories, which are Ancillary and Commercial Services, Contract Notifications and Bid – Offer Acceptance [17].

2.2.3.1 Ancillary and commercial services

Ancillary and Commercial Services includes reactive power, frequency response, black start and reserve services. These services are normally contracted in advance by the system operator, by dealing directly with the participants. Since these services are considered system balancing services, they are not used to level the energy differences between supply and demand. These services are for instance used to alleviate transportation issues and transmission system problems.

2.2.3.2 Contract notification

As for generators and suppliers, the system operator can buy and sell electricity ahead of gate closure. The TSO may therefore, ahead of gate closure, choose to contract the electricity it believes is required with participants in the market. If the IPN, for instance, indicates a surplus or a deficit in a given area, a contract notification may then enable National Grid to level out the anticipated imbalance.

2.2.3.3 Bid – offer acceptances

A balancing market is operated by the TSO, National Grid, where participants can make bids or offers. A bid is related to buying electricity, meaning that the participant is either increasing demand or decreasing generation, while an offer is a sale where they either increases generation or decreases demand. These bids and offers are used by the TSO to balance the system. Bid – offer acceptances are exclusively made after gate closure for the settlement periods. This system of bids and offers are called the balancing mechanism [17] as shown in Figure 2.7. In case of an imbalance, National Grid chooses bids that can meet the requirements and then selects the cheapest option. If a quick reaction is required, a pumped storage plant may be called upon, since such plant can ramp up quickly to full output. This may not be the cheapest option available, but might be the only one that meets the requirements. Bid or offer submitting in the balancing market indicates that the participants balancing mechanism unit can move away from its FPN after gate closure. Acceptance result in a deviation from the FPN, but the TSO will typically issue an acceptance which returns to the FPN at the end. The BM unit is therefore not exposed to imbalances in the next settlement period, due to a bid – offer acceptance.

2.2.4 Balancing settlement

As mentioned in section 2.2.3, the market participants are not obligated to keep a balance between their actual and their contracted position. The balancing settlement is therefore created in order to give them an incentive to maintain their balance. These incentives are not to be confused with National Grid's expenditures to keep the system balanced. Costs related to maintain the balance is covered by a balancing fee, which is called Balancing Service Use of System (BSUoS) [9]. These costs are distributed between all participants based on the proportion of energy they are feeding into the grid or extracting. This means that the balancing cost is distributed between all participants, and not just the ones that are causing the imbalances.

Participants causing imbalances are penalized through a settlement called Cash Out. The balancing settlement is carried out after the hour of operation as indicated in Figure 2.7. If a participant has used more electricity than contracted for, it has to buy additional electricity from the system and is then charged at System Buy Price (SBP). On the other hand, if a participant generates more electricity than contracted for, it has to sell the additional electricity to the system, and receives a payment at System Sell Price (SSP) [17]. SSP and SBP are estimated in such a way that SBP normally are considerably higher than the spot price, while the SSP normally is considerably lower. In 2006, SBP was 17.8 % higher than the spot price in average, while the SPP was 18.6 % lower than the spot price in average [9]. Imbalances may therefore be costly for the participants involved. A clearer explanation of the SSP and SBP are given in Table 2.1.

Table 2.1: System Sell Price and System Buy Price

	Supplier	**Generator**
System Sell Price (SSP)	Paid if you under-consume	Paid if you over-generate
System Buy Price (SBP)	Pay if you over-consume	Pay if you under-generate

Part II Model input

3 North European EMPS-model

EFI's Multi-area Power market Simulator model (EMPS) is a computer tool developed by SINTEF Energy Research. It has been in active use in the Norwegian and the Nordic market for more than two decades [15]. The EMPS model is a market simulator which optimizes the utilization of a hydro-thermal power system based on stochastic supply options and demand. This simulation tool provides the user with insight in price formation, energy economics, energy flow, environmental consequences and quality of delivered power [21] among others. It can also be used to simulate the utilization of local and national energy resources, for instance the interaction between a hydropower system and a thermal system. A more detailed, but brief description of the models mode of operations is given in Appendix C.

3.1 Model overview

The North European EMPS-model consists of two area types, simulation areas and border areas. A country may consist of several areas. Norway for instance, consists of 16 areas while Finland is only one area. Such a model needs a set of system borders or a coupling to the 'rest of the world'. Border areas are created to act as a coupling to the rest of the world in order to achieve a reasonable exchange from the simulated areas. These areas are modelled with a given demand which varies throughout the day and year. Generation is calculated based on the area's aggregated capacity per energy source. Each energy source, like hydro, nuclear, gas etc. has a given marginal cost per generated unit. This results in a rather rough description of the power market in these areas due to the plant modelling. As mentioned previously, the main purpose of the border areas is to obtain a reasonable exchange from the simulated areas to the 'rest of the world'. This task is sufficiently solved by this rough description through fixed exchange volumes to the neighbouring areas. The exchange is defined with annual fixed volume of export and import, which is based on statistical data for the areas. The exchange is then distributed throughout the year due to price differences between the areas. Border areas include France, Switzerland, Austria, Czech Republic and Poland, while Norway, Sweden, Finland, Denmark, Germany, The Netherlands, Belgium and Great Britain consists of simulation areas.

Power systems in the simulated areas are described in much more detail than the border areas. All the large plants are individually modelled with their marginal cost, start-up cost and capacity. The exception is nuclear, hydro, small scale CHP, bio and photovoltaic plants in the areas within Great Britain, Germany, Netherlands and Belgium. These are aggregated for each area with respect to the energy source. Wind farms are also aggregated for each area, resulting in one farm with the area's total installed capacity. Since the rest of the thermal plants are modelled individually, a total of approximately 700 plants are implemented in the model. After aggregating plants with the same name and marginal cost, over 500 remain. The EMPS-model is limited to 500 thermal plants and working close to this limit results in unacceptable computation times if start-up costs are included (more than a week). Further aggregation is required and a stepwise aggregation with 2.5 €/MWh steps are carried out. This means that every plant with the same type of fuel are aggregated within a given range of 2.5 €/MWh. The new marginal costs are then the average marginal cost of all the plants in each block. Thermal plants are then reduced to approximately 250, still resulting in a computation time of approximately 100 hours with a 2.27 GHz Inter Core i5 processor and 8 GB RAM. The data set for the model except Great Britain is based on [22].

3.2 Nordic area

The Nordic area has a large portion of hydropower, which is described very detailed in the model. Especially the Norwegian system is detailed since each individual plant, reservoir, waterway, duration of the water flow from station to station etc. are described, resulting in very realistic model for the power system. The hydro systems in Sweden and Finland are also well described, but not to the same extent as the Norwegian. Thermal plants in the Nordic area are modelled individually while wind farms are modelled in the same way as described in the previous section. The interaction between thermal, wind and hydro ensures a relative flat price with small variations throughout the day compared to thermal dominated systems. This is due to the flexibility such a large share of hydropower brings into the system.

Each area's demand is given by annual consumption, which is distributed throughout the day and year based on the area's respective load profile.

As for continental Europe, power systems in the Nordic area are strongly integrated through lines and cables. Every EMPS-area which is connected to another area has a defined transfer capacity with a given transmission loss. The loss is assumed to be proportional to the transferred volume and is therefore given as a percentage of the transfer. This factor is varying from 0.1 % in lines connecting nearby dense populated areas, to 4 % in the NorNed cable between Norway and The Netherlands. A map of all areas in the model, including area connections, is sketched in Figure 3.1. Simulated areas are coloured blue, while border areas are coloured green. More details about the area's name and location are given in Appendix D.

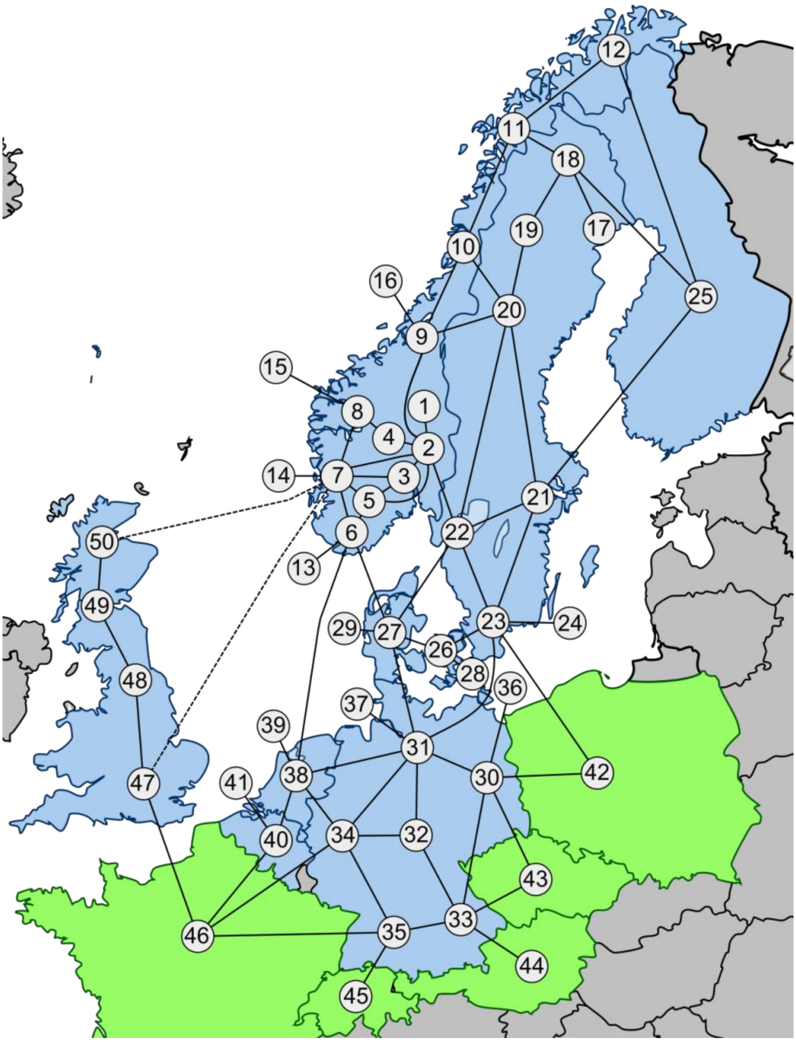

Figure 3.1: Areas and area connections in the 2010 EMPS-model

4 Great Britain EMPS-model

4.1 Areas

The Great Britain EMPS-model consists of four separate areas. Each area has a demand, generation capacity and exchange capacity to the surrounding areas. Since the model does not allow for transmission capacities within areas, the areas have to be defined based on potential transmission constraints. The areas are therefore chosen based on a compromise between transfer constraints and available characteristics for demand and supply, which is normally given as regional data. The chosen boundaries are equal to boundary 2, 6 and 9 in [23].

Scotland is divided in two areas, which are named GB-ScotN and GB-North. GB-ScotN includes Aberdeen City, Aberdeenshire, Moray, Highland and Na h-Eileanan Siar. Islands without cable connection to the main land, like Shetland and Orkney, are not included in the model. The remaining Scottish counties to the south are included in GB-North. GB-Mid consists of North East, North West, Yorkshire and the Humber, East Midlands, West Midlands and the northern parts of Wales. GB-South represents East of England, Greater London, South East, South West and the southern part of Wales. These four areas are defined in Figure 4.1.

Generation to the north of the boundary separating GB-ScotN and GB-North is expected to increase significantly in the coming years. This is due to a high volume of new wind generation seeking connection in this area [18]. An increase in generation requires an increase in transfer capacity. Presently, the boundary has spare capacity and the transfer capacity is expected to increase at a similar rate as the generation. The basis for selecting this boundary is therefore not based on internal conditions in Scotland, but rather external. An interconnector between Norway and the Aberdeen area would increase the area's available capacity with approximately 50 %, which might lead to transmission constraints at the boundary.

The second boundary is separating GB-North and GB-South. This boundary is named Cheviot after the Cheviot Hills, a range of rolling hills straddling the border between England and Scotland. Similar to GB-ScotN, GB-North is expected to have an increase in generation, due to new contracted renewable energy throughout the area. Presently, the required capability is significantly in excess of the current capability, indicating a strong need for reinforcements in the coming years. An interconnector from Norway to the Aberdeen area may increase this excess capacity further.

GB-Mid and GB-South is divided by a third boundary. Presently, the boundary's transfer capacity is slightly higher than the required transfer, but a reduction in transfer is expected from 2016 resulting in more spare capacity.

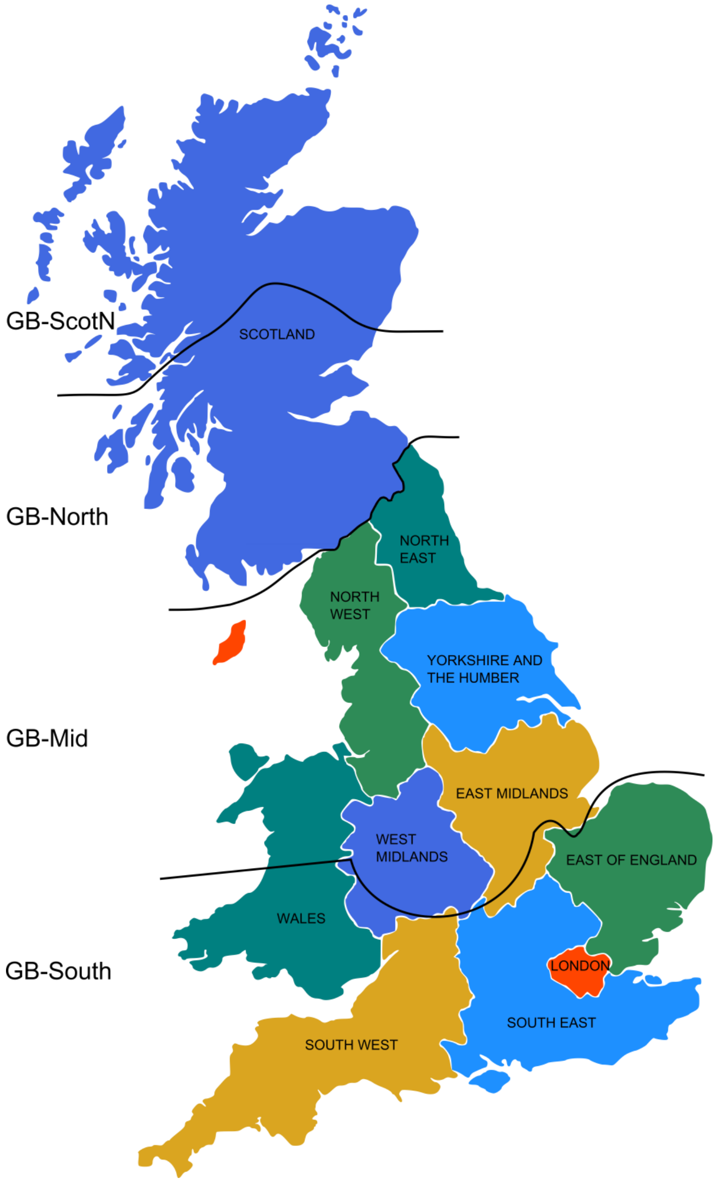

Figure 4.1: Areas and transmission boundaries in the Great Britain EMPS-model.

4.2 Transfer capacity

The four areas are separated from each other by boundaries, which have a limit on the bulk transfer of power. This limit is based on two types of system limitation given by the Licence Standard [18]. Voltage capability is the first while thermal capability is the second important factor. A combination of these factors results in the transfer capability (the red line) as sketched in Figure 4.2. It is also required by the Licence Standard that a boundary, where two circuits are out of service, must be able to transfer the planned transfer plus half the calculated interconnection allowance without any unacceptable conditions arising [18]. The boundary must therefore be able to handle either a double circuit event (N-D) or a simultaneous circuits outage of any two circuits (N-2) in the network [24]. Boundaries with demand below 1500 MW (winter peak) are excepted since they only must be able to transfer the planned transfer. This exception applies for boundaries in the northern parts of the SHETL area in Scotland (Boundary B1, B2 and B3 in Appendix E)

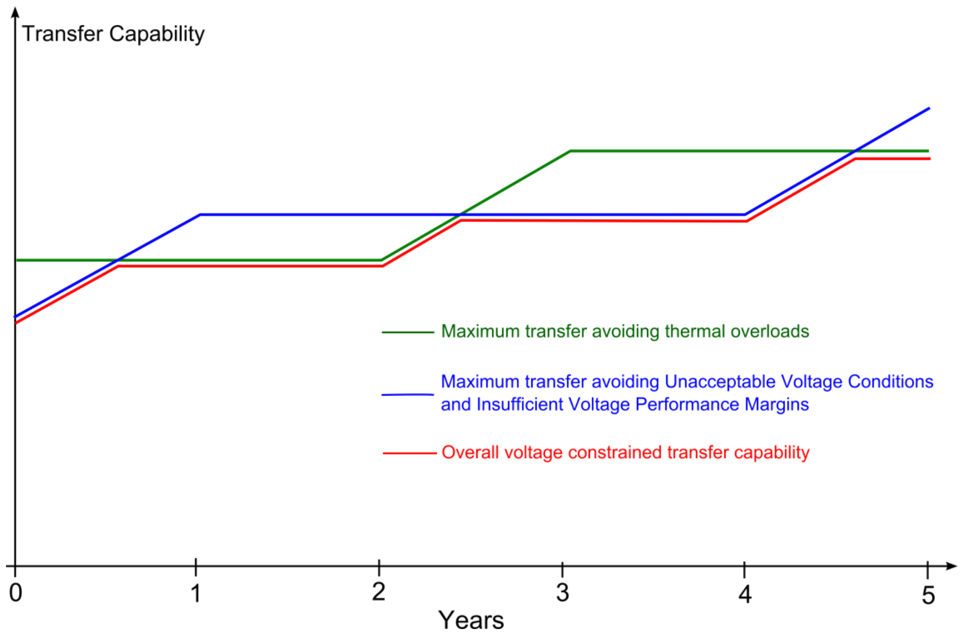

Figure 4.2: Calculation of the transfer capacity across a boundary. Based on [18].

Transmission capacity is set to 1 600 MW for the GB-ScotN - GB-North boundary, 2 800 MW for the GB-North - GB-Mid boundary and 12 500 MW for the GB-Mid - GB-South boundary. A more detailed map of the boundaries is given in Appendix E (Boundary B2, B4 and B9).

4.3 Generation

Great Britain generation mixes for 2010 and 2009 are given in Figure 4.3. This figure indicates that gas, coal and nuclear are the dominating energy sources for electricity generation, although the share of renewables are expected to rise considerably in the coming years.

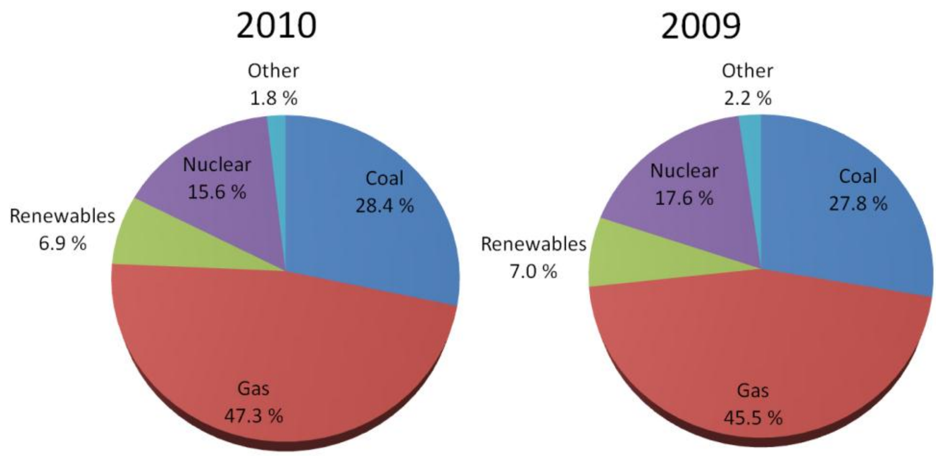

Figure 4.3: Generation mix for 2010 and 2009 in Great Britain [25] (electricity supplied).

4.3.1 Nuclear generation

Nuclear generation is modelled with a fixed annual generation volume, which is based on the actual generation for the last two years. Total generation in 2010 was 61.1 TWh, down from 67.4 TWh the previous year. The supply fell by 10.1 %, due to technical problems at some stations [25]. Annual generation from nuclear plants is therefore estimated to be approximately 64 TWh in the model. This is a bit higher than the generated volumes for the previous years, given in Appendix F.

The output is assumed to be constant in all load periods throughout the year. This assumption is based on several factors. Nuclear plants have a very high investment cost while the atomic fuel is cheap in comparison. They should therefore generate as much as possible. Additionally, changes in output including start-up are costly since the process is very time consuming and the energy loss due to regulation is quite high. This is an incentive for the producers to keep the output at a constant level. Another factor is the need for maintenance which is hard to predict. Even though most of the planned maintenance is carried out during the summer, it is not implemented in the model for simplicity reasons. Nuclear power is therefore running as a constant base-load in the model. The annual generation in each area are calculated in Appendix F resulting in the nuclear distribution given in Table 4.1.

Table 4.1: Annual nuclear generation in each area

Area	Annual nuclear generation (TWh)
GB-South	22.6
GB-Mid	26.2
GB-North	15.2
GB-ScotN	0.0
Total	64.0

4.3.2 Wind generation

The data for wind simulations are fetched from the TradeWind project [26]. This data is based on a nodal grid with a nodal distance of 50 km. Every node has known wind speeds for the last decades. Wind speeds for several sites in Great Britain are calculated by linear interpolation between these nodes, resulting in wind data for several onshore and near shore sites. These data series are then combined into one single wind series for the entire Great Britain. The level of detail is the largest drawback for this method. It is obvious that some sites have a higher average wind speed than others, which are not allowed for with only one wind series. The second problem is the coincident variations in wind speeds at the different wind farms. One single wind series evens out the local variation, meaning that if the wind in reality was merely blowing in Scotland, this would be evenly distributed in the entire Great Britain. The farms in Scotland would therefore be producing less while the farms in the rest of Great Britain would produce more according to the wind series, even if these sites had now wind in reality. This way of levelling wind speeds is reducing the wind farms influence on boundary capacities since there are no differences in wind speeds on either side of the boundary.

Similar to the inflow data, wind data is based on series of several consecutive years. Each year consists of wind data with a resolution of six hours. The program is then using linear interpolation to calculate the hourly wind speeds.

The input in the program is rather wind efficiency than wind speed. Wind efficiency is a factor for the output per unit installed capacity. Meaning, if the wind efficiency at some point is 60 % and the installed capacity is 1 MW, the output would be 0.60 MW. Average weekly wind efficiencies for Great Britain are given in Figure 4.4. This efficiency also states that 1 MW installed capacity in Scotland is generating the same amount of energy as 1 MW installed in the southern parts of England. Installed capacity of wind farms larger than 7 MW is given in Table 4.2.

Table 4.2: Each area's total installed capacity of wind farms larger than 7 MW [26]

Area	Installed capacity (MW)
GB-South	800
GB-Mid	50
GB-North	1 251
GB-ScotN	741

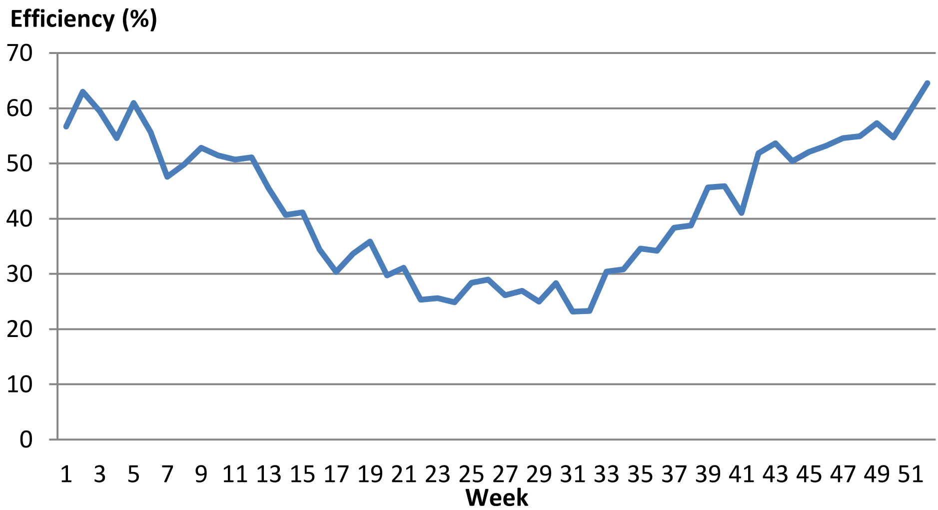

Figure 4.4: Wind efficiency in Great Britain for an average year

4.3.3 Hydro and pumped storage plants

Hydro generation within each area is aggregated as one power plant with an associated reservoir. A graphical illustration of the aggregated plant is given in Figure 4.5. The inflow consists of non-storable inflow and storable inflow, which is assumed to be 30 % and 70 % of the total inflow respectively. Non-storable inflow cannot be stored in the reservoir, resulting in a continuous use of the water. If the inflow exceeds the discharge capacity, the excess is spilled. Storable inflow ends up in the reservoir which has a fixed capacity. Exceeding this limit, results in spillage. The inflow in Great Britain is based on scaled scenarios from the Southern part of Norway. Norwegian data is used for simplicity reasons, including the absence of adapted inflow data from Great Britain and the need for data with yearly and seasonal variations. The average annual production is approximately 5.2 TWh [27]. This volume is for simplicity reasons divided between the areas based on their installed capacity, resulting in the percentage distribution given in Table 4.3.

Table 4.3: Allocation of hydro generation in Great Britain

Area	Share of total hydro generation
GB-South	5.0 %
GB-Mid	4.1 %
GB-North	43.3 %
GB-ScotN	47.6 %

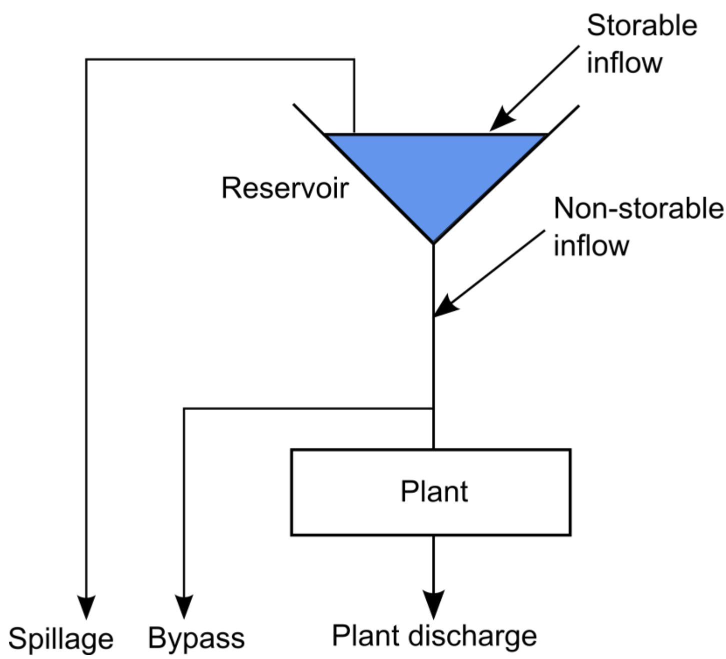

Figure 4.5: Hydro power module [15]

The EMPS program's ability to simulate day and night pumping is at best limited. Such temporary pumping is not yet included in the program. Implementation of a reasonable representation of the pumped storage is therefore quite hard. The energy used for pumping is included in the overall consumption related to the plants respective area. Generation from pumped storage is modelled as a fixed contract which depends on the price and the load period. Most of the pumping is carried out during low load periods, like night and weekend, when the electricity prices are lowest. Electricity prices in these load periods are quite constant throughout the year. The total energy loss related to pumping and regeneration is assumed to be 30 %, indicating that the plant's marginal cost is approximately 30 % higher than the electricity prices during low load periods. These contracts are therefore only activated if the price level exceeds the average 'low load' price plus 30 %. Contracts are also dependent on the load periods since the contracts only can be activated during high load periods. This limitation is representing the storage capacity of the plants since generation at some plants are limited to six hours at maximum discharge, due to the reservoir volume. The annual generation is set to approximately 3.9 TWh [27] and distributed based on installed capacity. An overview of the allocation of pumped storage generation in Great Britain is given in Table 4.4.

Table 4.4: Allocation of pumped storage generation in Great Britain

Area	Share of the pumped storage generation
GB-South	0 %
GB-Mid	73 %
GB-North	16 %
GB-ScotN	11 %

4.3.4 Combined heat and power

The largest CHP plants are modelled as coal, gas or oil plants while smaller plants are aggregated into one plant for each area. The electrical capacity of these small plants are given in [27] and they are assumed to deliver a flat output with a total installed capacity of 2 036 MW. Electricity generation from CHP-plants are highest during winter since the increased demand for heating enables the plant to utilize the surplus heat. Despite these yearly variations, the output is assumed flat as a simplification. The allocation of CHP in Great Britain is given in [28] (major and other producers). For simplicity reasons, it is assumed that these areas also have the same share of small CHP. By using the average UK-load factor for the CHP [28], an estimate of generated electricity can be made. Generation details for each area are given in Table 4.5. Since the CHP data is given for Scotland in its entirety, the distribution of CHP between GB-ScotN and GB-North are assumed to be proportional to the area's electricity demand.

Table 4.5: Electricity generated by small CHP plants in Great Britain

Area	% of total CHP	Capacity (MW)	Load Factor (%)	Electricity generated (TWh)
GB-South	23	468	62.4	2.56
GB-Mid	66	1344	62.4	7.35
GB-North	9	181	62.4	0.99
GB-ScotN	2	43	62.4	0.24

4.3.5 Coal, gas and oil fired plants

Details about the coal, gas and oil fired plants in the model are given in [27] including their installed capacity, fuel type and station name. Based on the power plant data from [22], marginal cost and start-up cost for each individual plant can be determined. The marginal cost and start-up cost for each individual plant are estimated based on plant type, age and fuel cost. Fuel cost can be varied according to current prices or future expected prices. The plants are ranked in merit order based on their marginal cost, which results in start-up of the cheapest power plant first when more output is required. If a reduction of output is needed, the most expensive unit is disconnected first, assuming no start or stop costs. By including the start and stop costs, an evaluation has to be executed of which alternative is more costly, turning off the unit or keep it running even though the market price is lower than the unit's marginal cost for a given period.

The number of plants in the model is reduced due to the limitations mentioned in section 3.1. For Great Britain alone, about 120 coal, gas and oil plants are individually modelled. These are aggregated in order to reduce the number of plants, which makes it possible to obtain a solution and to reduce computation time. The aggregation is based on the plants fuel type and their marginal cost. A stepwise aggregation with 2.5 €/MWh steps are carried out. This means that every plant with the same type of fuel are aggregated within a range of 2.5

€/MWh. The new marginal costs are then the average marginal cost of the plants in each block.

The availability of the power plants is given as an input to the model. This parameter can be changed separately for the different plant categories (coal, gas and oil). Additionally, the availability fluctuates quite a lot through the year. Most of the planned outages are during low load periods in the summer. The time and the time span for unscheduled outages, on the other hand, are impossible to predict. In order to get more realistic outage data for each fuel category, three consecutive years of outage data (2007-2009) from the European Energy Exchange (EEX) are used as a basis for the outage data. Average weekly values for these years are smoothed based on two weeks prior to and two weeks afterwards the particular week. Relative values for each week (average value is 1) are then calculated and multiplied with the corresponding availability factor for the plant. Availability for each plant category is given in Table 4.6.

Table 4.6: Availability based on plant category

Plant category	Availability (%)
Hard coal	70
Gas	90
Oil	95

4.3.6 Reserves

In order to keep the system stable, some reserves are required for rapid regulations. The regulating reserve in Great Britain is roughly 450 MW and the standing reserves are 2 255 MW [29]. Both reserves categories are considered momentary reserves by the EMPS-program, adding up to a total reserve capacity of 2 700 MW.

5 Demand

Supply and demand data for Great Britain are given in Table 5.1. Total demand is the sum of all consumed electricity in Great Britain including consumer sales, transmission losses, electricity used for generation, electricity used for pumped storage and electricity used in other energy industries.

Table 5.1: Key figures for Great Britain electricity system 2007-2010 [27] and [24] (GWh)

Year	2007	2008	2009	2010
Production	392 972	384 579	371 978	381 247
Pumped storage	3 859	4 089	3 685	3 150
Imports	8 613	12 294	6 609	7 144
Exports	-3 398	-1 272	-3 748	4 481
Total Supply	402 046	399 690	378 524	383 910
Total Demand	401 669	399 387	378 714	383 212
Statistical Difference	377	304	-190	698
Losses	26 469	27 619	26 912	28 769

5.1.1 Area demand

Demand for the various areas are based on data from [30]. Total annual demand in Great Britain in 2009 was 379 TWh and 383 TWh in 2010, which is a considerable decrease compared to 2008 and 2007. Final consumption of electricity (not including losses) rose by 0.9 % in 2010 compared with 2009. This was distributed by a 0.4 % increase in the domestic sector, 3.4 % increase in industrial use and a 0.8 % decrease by other final users [25]. The demand in the model is set to 381 TWh, based on data for 2009 and 2010.

The allocation of demand is calculated from consumer sales in Great Britain which is given in Table 5.2. These data is fetched from [30], where each county's consumption is defined. In order to simplify the model it is assumed that the transfer boundaries are similar to the county borders. ScotN are therefore including Aberdeen City, Aberdeenshire, Moray, Highland and Na h-Eileanan Siar, while the rest of the counties in continental Scotland is included in GB-North. The boundary separating GB-North and GB-Mid (The Cheviot-boundary) is following the frontiers between Scotland and England. GB-Mid consists of North East, North West, Yorkshire and the Humber, East Midlands, West Midlands and the northern part of Wales which includes the Welsh counties Conwy, Denbighshire, Flintshire, Gwynedd, Isle of Anglesey and Wrexham. GB-South includes the Southern part of Wales (the rest of the Welsh counties), South West, South East, London and East of England. See Figure 4.1 section 4.1 for a graphical overview of the counties and boundaries.

Table 5.2: Consumer sales in the Great Britain counties for 2009 [23].

Area	Consumer sales (GWh)
Scotland North	5 277
Scotland South	21 734
North West	32 442
West Midlands	24 624
Yorkshire and the Humber	24 372
East Midlands	21 185
North East	12 034
Wales North	3 795
Wales South	11 925
East of England	26 956
Greater London	41 081
South East	39 747
South West	24 904
Sum	290 075

The sum of consumer sales does not include pumped storage, electricity used for generation, sales direct from high voltage lines, unallocated consumption and more. Remaining consumption, approximately 90 TWh, is allocated based on a set of assumptions. Details about the assumptions and calculations are given in Appendix G. By summing up the total consumption for each county, a calculation of each EMPS-areas total demand can be performed. Demand in the four areas is given in Table 5.3.

Table 5.3: Area demand

	Demand (GWh)	Demand
GB-South	185 057	48.6 %
GB-Mid	158 557	41.6 %
GB-North	29 664	7.8 %
GB-ScotN	7 722	2.0 %
Sum	381 000	100.00 %

5.1.2 Annual weekly demand

The demand in Great Britain varies quite a lot over the year, with the highest consumption during December/January and the lowest in July/August. A graphical description of the weekly demand in Great Britain for 2009 is given in Figure 5.1. These values are based on half-hour demand representing total gross system demand [31], which includes consumer demand, station load, pumping and interconnector exports. All half-hours for each week are summed up resulting in the weekly demand curve. Based on these values, relative weekly demand values can be calculated and used as an input in the model. It is assumed that the relative demand values are similar for all areas, i.e. all areas have the same weekly demand profile.

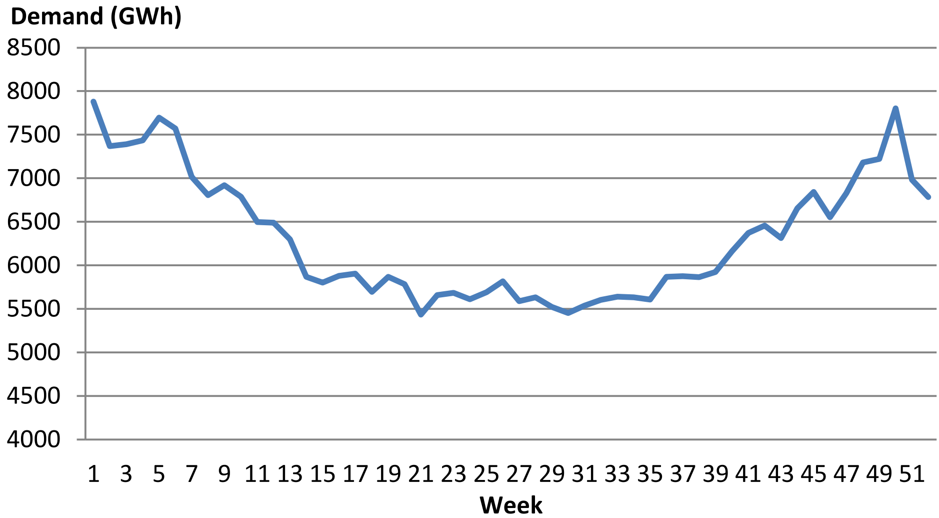

Figure 5.1: Weekly demand in Great Britain for 2009

5.1.3 Load periods

The load fluctuates a lot during days, nights or weeks for a power system and it is therefore impossible to simulate this in detail within a reasonable computation time. This is, to some extent, solved by defining load periods, which is an aggregation of periods with similar load throughout the week. For the Great Britain model, seven load periods are defined as inputs to the model. These are defined in Table 5.4. The average load in these periods are calculated from half-hourly data for 2009 [31]. Load period 1 is the average demand for every workday half hour from 09:00 to 15:00 throughout the entire year. The other load periods is also calculated for an entire year in their respective time periods. It should be noted that this computation does not take into account the public holidays in 2009. This means that for instance 1. January, which was a Thursday, should be considered a Sunday in the load period calculations to achieve more realistic results.

Table 5.4: Load periods

Weekdays	**Load period**	**Average load (MW)**
00:00 – 05:59	4	33 648
06:00 – 08:59	3	41 714
09:00 – 14:59	1	44 086
15:00 – 17:59	3	41 714
18:00 – 19:59	2	44 511
20:00 – 23:59	4	33 648
Weekend - Saturday		
00:00 – 06:59	6	29 507
07:00 – 23:59	5	35 781
Weekend - Sunday		
00:00 – 06:59	7	28 293
07:00 – 23:59	5	35 781

By combining these load periods, an average weekly demand can be sketched. This is illustrated in Figure 5.2.

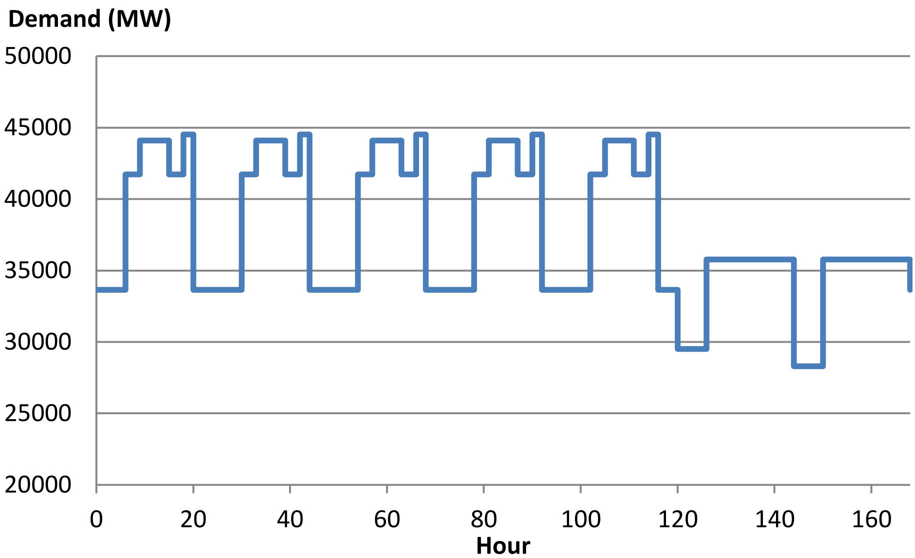

Figure 5.2: Weekly variations in demand based on average yearly values for the seven load periods

Load periods are also used to present the outputs from the model. Every period returns an individual price, production, exchange, wind generation etc. from the simulations. Since each week consists of seven load periods as defined in Table 5.4, may for instance the generation for a specific week be assembled from these periods resulting in a distribution similar to the one sketched in Figure 5.2.

6 2020-scenario for Great Britain and Northern Europe

The power systems in Great Britain and the northern parts of continental Europe are presently undergoing one of the most rapid changes in history due to EU's ambitious targets for renewable energy. In 2020, a 15 % share of the gross consumption of energy in United Kingdom, 18 % in Germany and 14 % in The Netherlands are determined to generate from renewable sources, compared to 1.3 %, 5.8 % and 2.4 % respectively in 2005 [32]. Most of the increase, related to the amount of renewable energy, is expected to take place in the electricity sector. Since most of the potential for hydropower already are utilized, and tidal, solar and waves are much more costly technologies, wind is assumed to be the most important renewable source in order to reach these targets. Other important factors are more bio energy as well as advances in energy efficiency. The amount of wind capacity needed indicates a drastic shift in the respective country's generation capacity mixes. A scenario which covers the Great Britain targets for 2020 is composed by National Grid and named Gone Green [33]. Assumed generation capacity mix in 2020 based on this scenario is given in Figure 6.1. Such growth in the generation from wind farms is assumed to be too ambitious and a scenario with less increase is used in the model.

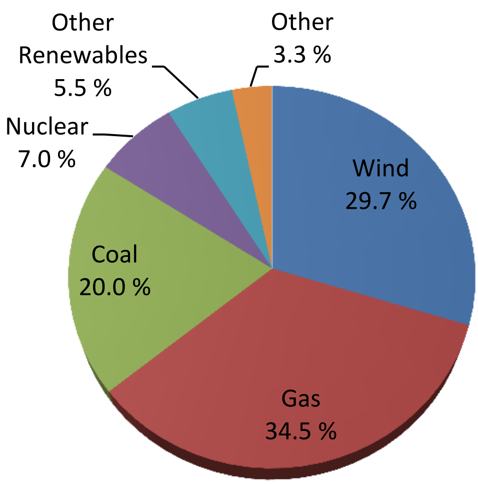

Figure 6.1: Great Britain's capacity mix for 2020 based on the Gone Green scenario [33]

The data set for the Nordic and continental Europe 2020 scenario are fetched from a development of [22]. Great Britain is therefore the main focus in this section.

6.1 Areas and transfer capacity

EMPS-areas in the 2020 scenario, for both Great Britain and the rest of Northern Europe, are equal to the areas in the model of the 2010 power system. This is described in section 4. A map of the areas and their transfer 'lines' for the 2020 Northern Europe scenario is given in Figure 6.2, while Figure 4.1 section 4.1 has a more detailed division of the areas in Great Britain.

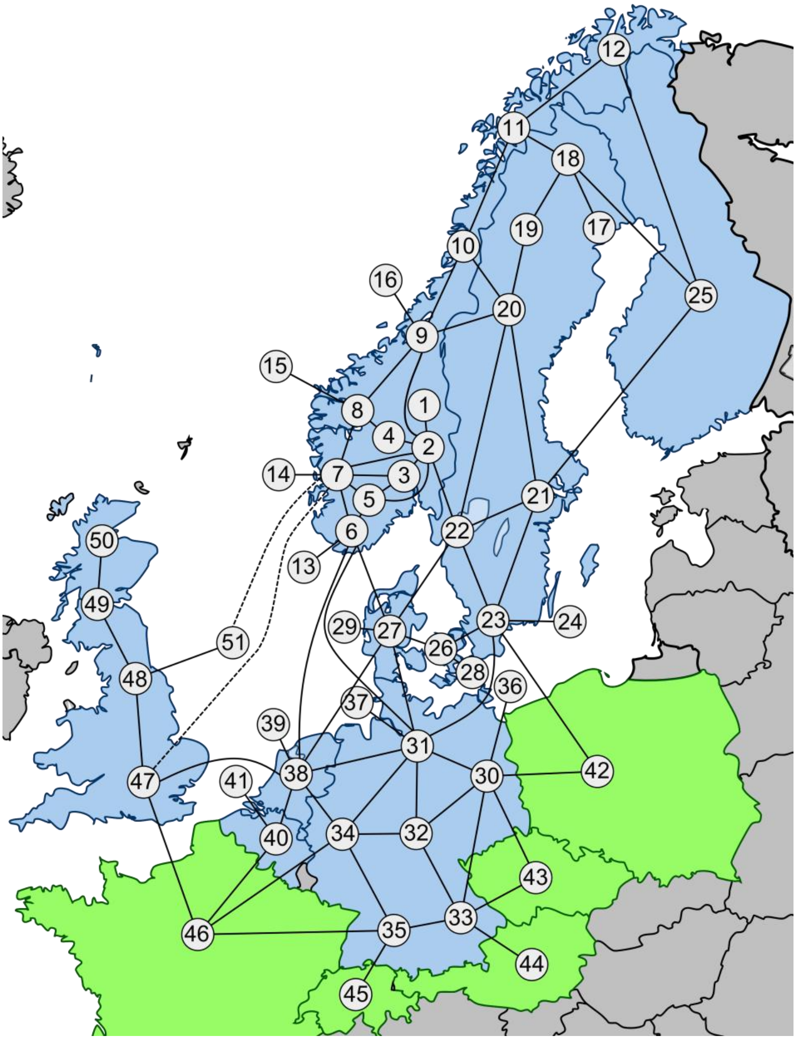

Figure 6.2: Areas and area connections in the 2020 EMPS-model

There are several reasons for using the same areas in both scenarios, but the most important reasons is to make it easier to observe the changes from the 2010 scenario to the 2020 scenario. The areas are also determined based on weaknesses in the transmission grid. Borders which are subjected to transfer constraints today are also, to some extent, assumed to face constraints in the 2020 scenario.

A large share of the onshore wind farms is assumed to be located in the northern parts of Scotland. Plans for a considerable reinforcement are therefore displayed for the boundary between GB-ScotN and GB-North. This comprises the replacement of the existing 132 kV double circuit tower line between Beauly and Denny by a new 400 kV double circuit tower line [18]. This reinforcement is due to be completed in 2013 and will increase the boundary capability by approximately 1 050 MW to a total of 2 650 MW. An upgrade of the 275 kV east coast line, from Blackhillock to Kincardine, to 400kV will strengthen the boundary further. Expected completion time of the line is 2015. Completion of this upgrade is based on the volume of renewable capacity connected to the north of the boundary. Several other upgrades have also been proposed, such as an East Coast HVDC link from Peterhead to Hawthorne Pit and subsea links to the Western Isles, Orkney and Shetland [34]. The timeframe and level of realization for these projects is associated with some uncertainty. Transfer capacity for the boundary is therefore set to 2 650 MW.

The required transfer capability for the boundary separating GB-North and GB-Mid is currently exceeding the actual capability. More renewable generation capacity in Scotland increases the required transfer further and an extensive reinforcement program is therefore launched. This includes conductor replacements resulting in a higher continuous rating and lower impedance, new transformers and reactive compensation [23]. Upon completion of these upgrades, this boundary continues to show insufficient transfer capabilities for the assumed required transfer. This indicates that further reinforcement is required and series compensation and offshore HVDC schemes have been proposed. One of the propositions is a HVDC link connected between Hunterston in Scotland and Deeside in Wales with a capacity of 1 800 MW [34]. Another possibility is the HVDC link mentioned previously from Peterhead to Hawthorne Pit. If required, some of these upgrades could increase the transfer capability to a total of 5800MW by 2015/16. Since the renewable capacity growth in Scotland is assumed to be high in the model, the boundary transfer capacity is set to 5 800 MW.

Boundary transfer between GB-Mid and GB-South is expected to decrease to approximately 11 500 MW in 2014/16 due to connection of southern generation [23]. This capacity is therefore used in the 2020 scenario.

6.2 Generation

Presently, the total installed capacity in Great Britain is about 83 GW [27] and an increase is expected towards 2020. Several reports on the topic indicate more installed capacity in 2020, but the assumed values differ a lot. An overview of these numbers is given in Table 6.1. BAU means Business as usual, while the Low, Mid and High scenarios for SKM are categorised based on the amount of installed wind generation. Since the increase in wind generation is assumed to be considerable and not extremely high, most of these scenarios are assumed to have too much wind generation. Installed capacity in 2020 is assumed to be in between the BAU and the Gone Green scenarios from National Grid. Regardless of the wind capacity's growth are high or moderate, the total capacity is forced to increase. Output from a wind farm depends on the wind speeds at their specific location, which can have a high volatility. The power system is therefore depending on extra capacity which can replace the wind generation in case of calm air. Even though there is an increase in generation capacity, the peak demand and the annual consumption are not expected to increase. This indicates a reduction in utilisation time for some units and especially the thermal units.

Table 6.1: Generating capacity for various scenarios in 2020 [34].

	National Grid		Redpoint			SKM			
2020 (GW)	**BAU**	**Gone Green**	**Status Quo**	**RO32no SB**	**RO37S B**	**BAU**	**Low**	**Mid**	**High**
Coal	23.1	19.8	23.7	15.0	16.5	23.3	21.5	21.4	20.1
Gas	39.1	34.1	41.0	41.3	38.9	32.4	27.9	26.4	25.9
Nuclear	6.9	6.9	3.7	3.7	3.7	6.0	6.0	6.0	6.0
Wind	15.8	32.3	12.2	28.1	28.1	4.7	32.9	38.5	48.4
Renewables	4.3	8.0	4.1	8.0	8.2	2.4	4.4	5.2	5.6
Other	3.8	3.8	3.5	3.5	3.5	5.8	5.8	5.8	5.8
Total	93.0	104.9	88.2	99.6	98.9	74.6	98.5	103.3	111.8
Demand TWh	373	365	372	360	360	n/a	n/a	n/a	n/a

6.2.1 Nuclear generation

Nuclear generation is strongly influenced by political decisions, making it hard to predict the nuclear share of generation in 2020. In theory, political decisions could close down all plants or give incentives for an increased priority of nuclear power. Installed nuclear capacity in 2020 is based on [34] and the assumption that only Wylfa B and Hinkley Point C Stage 1 are built before 2020, adding up to a total capacity of 7 GW. The capacity factor is assumed to be 80 % resulting in an annual generation of 49 TWh. An overview of the assumed operating plants is given in Table 6.2.

Table 6.2: Operating nuclear plants and their capacity in 2020

Area	Plant name	Capacity (MW)
GB-South	Sizewell B	1 200
GB-South	Hinkley Point C Stage 1	1 670
GB-Mid	Heysham 2	1 230
GB-Mid	Wylfa B	1 670
GB-North	Torness	1 215
Sum		6 985

All plants are assumed to have the same capacity factor, resulting in the distribution given in Table 6.3 of annual generation with respect to the plant's location.

Table 6.3: Nuclear generation in 2020 with respect to the areas

Area	Annual generation (TWh)
GB-South	20.1
GB-Mid	20.3
GB-North	8.5
GB-ScotN	0
Sum	49.0

6.2.2 Wind generation

The largest expected change in the generation mix from today to 2020 is related to the increased priority on wind generation. As for nuclear, the volume of installed wind capacity is depending on political decisions. In order to make wind profitable, subsidies are required. In Great Britain these subsidies are given as feed in tariffs per generated kWh. It is assumed that these tariffs are kept steady until 2020 in order to provide incentives for realization of planned projects. Raised tariffs would most likely increase investments, while a reduction would decrease the number of investments. An overview of the present tariffs is given in Table 6.4.

Table 6.4: Feed in tariffs for wind generation in Great Britain [35]

System size	Tariff (€c/kWh)[1] Apr 2010-Mar 31 2011	Revised Tariff (€c/kWh)[1] Apr 2011-Mar 31 2012	Duration (years)
≤1.5kW	40.2	42.1	20
1.5-15kW	31.1	32.6	20
15-100kW	28.1	29.4	20
100-500kW	21.9	22.9	20
500kW-1.5MW	10.9	11.5	20
1.5-5MW	5.2	5.5	20

The 2020 scenario is based on the same wind series as the 2010 scenario described in section 0. This means that there is still only one wind series for both onshore and near shore sites. The exception is Dogger Bank which is implemented as a separate area in the model. In lack of wind data, a wind series from a Dutch offshore node is used as input for Dogger Bank. Forewind, the consortium developing Dogger Bank, has agreed with The Crown Estate a target installed capacity of 9 GW [35]. It is assumed that there will be few restrictions in developing this area and the total installed capacity in 2020 is assumed to be 3.6 GW [36]. Installed wind capacity for the areas in Great Britain are based on [18] and the data set from [37] resulting in the distribution given in Table 6.5. These capacities include both onshore and offshore farms.

Table 6.5: Installed wind capacity in Great Britain for the 2020 scenario

Area	Installed capacity (MW)
GB-South	5 676
GB-Mid	3 341
GB-North	4 735
GB-ScotN	3 350
Dogger Bank	3 600
Sum	22 738

[1] Exchange rate 1 GBP = 1.16395 EUR

6.2.3 Hydro power generation and pumped storage

Both the installed capacity of hydro power and the inflow are similar to the 2010 scenario described in section 4.3.3. The capacity distributions with respect to the areas are given in Table 4.3 in the same section. Pumped storage is also modelled in the same way, with the same capacities as the 2010 scenario. The allocated generation is given in Table 4.4 section 4.3.3.

6.2.4 Combined heat and power

Large CHP is still modelled as individual plants while small plants are aggregated for each area. The total installed capacity in the 2010 scenario was approximately 2 GW and for simplicity reasons this is also the capacity for the 2020 scenario. The allocation of capacity is considered equal to the 2020 scenario and an overview, with respect to the areas, is given in Table 4.5 section 4.3.4.

6.2.5 Coal, gas, bio and oil fired plants

All thermal plants fired by coal, gas, bio and oil are modelled individually with start-up cost, marginal cost and capacity. As for the 2010 scenario the number of plants, in the 2020 scenario, exceeds the model's thermal plant limit. The plants are therefore aggregated based on the method described in section 4.3.5. Data for 2020 are based on [18] and the data set from [26]. According to these data, the total capacity from present and planned plants is much higher than required, meaning that it is not economic reasonable to construct all of them. Some plans for new plants are therefore assumed abandoned based on the energy surplus in their areas. Both average annual availability and annual fluctuations of the availability is equal to the 2010 scenario described in section 4.3.5. Average annual availability for the different fuel types are given in Table 6.6.

Table 6.6: Annual average availability for coal, gas, bio and oil fired plants

Plant category	Availability (%)
Hard coal	70
Gas	90
Bio	90
Oil	95

6.2.6 Reserves

Reserve requirements are assumed to increase towards 2020, due to the expected rise in installed wind capacity. The reserves are therefore assumed to increase to 3 500 MW.

6.3 Demand

The demand in Great Britain is assumed to decrease in the coming years. Several factors are influencing the consumption, but more focus on energy saving and lower estimated economic growth is two of the main explanations. Demand in 2020 is set to 370 TWh based on the reports presented in Table 6.1. The allocation within Great Britain is assumed to be equal to the 2010 scenario, meaning that every area have the same share of the consumption as for the 2010 scenario. Each area’s annual demand is given in Table 6.7.

Table 6.7: Area demand for 2020

	Demand (GWh)	Demand (%)
GB-South	179 709	48.6 %
GB-Mid	153 994	41.6 %
GB-North	28 823	7.8 %
GB-ScotN	7 511	2.0 %
Sum	370 000	100.0 %

Relative values for both weekly demand and load period demand are similar to the values in the 2010 scenario. Weekly demand is illustrated in Figure 5.1 while the load periods are given in Table 5.4 section 5.

Part III Analysis and discussion

7 EMPS simulations for the 2010 scenario

All simulations are carried out based on the areas and connections illustrated in Figure 3.1 in section 0, plus different cable alternatives between Great Britain and Norway. The HVDC link from GB-South to The Netherlands is not included since the cable is not reaching full capacity until 1. June 2011 [38]. Fuel prices are similar in all countries except for the gas price, which is lower in Great Britain. Coal and oil prices for the entire model and the gas price in Great Britain is fetched from [39], while gas price in the rest of Northern Europe are equal to the German price. These prices represent the average price for fuel purchased by major power producers. The German gas price is calculated based on the assumption that the price paid by major power producers is 5 % higher than the average gas price at the frontiers [40]. The price in Germany is also assumed to be representative for the surrounding countries. An overview of the fuel prices are given in Table 7.1.

Table 7.1: Fuel prices for the 2010 scenario

Fuel	Price €/MWh
Coal	9.8
Gas (Great Britain)	17.0
Gas (Northern Europe except Great Britain)	21.6
Oil	57.5

Three different cases are discussed in this chapter. Case 1 and Case 2 includes a cable from Southern England to Southern Norway. In both cases the cable capacity is 1400 MW and the only difference is the gas price paid by major power producers in Great Britain. The third case is based on the same model parameters as Case 1, but instead of a connection to Southern England, the cable from Norway is connected to Northern Scotland. Model simulation is based on 40 historical consecutive years where the hydro inflow and wind is known. Especially for hydro, yearly variations in inflow may vary quite a lot. The results are therefore presented either as a wet, a normal or a dry year. The same historical years are used in all results and discussions. 1967, 1974 and 1978 are used as a wet, a normal and a dry year respectively. The wet year is close to the 90 percentile of these 40 historical years. Meaning that approximately 90 % of these 40 years have less inflow than the 'wet year' while 10 % have more inflow. The normal and the dry year are close to the 50 and 10 percentile respectively.

7.1 Case 1: HVDC link between GB-South and Southern Norway

A HVDC cable is connected between GB-South (area 47) and Nor-VestSyd (area 7) as illustrated in Figure 7.1. The transfer capacity is set to 1400 MW for both directions, while transmission losses in the cable are assumed to be 4 %. Fuel prices in the model are given in Table 7.1.

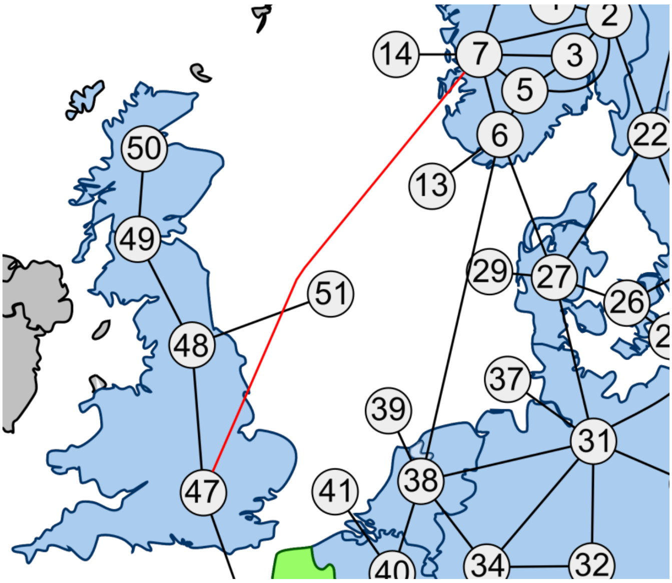

Figure 7.1: HVDC link (red line) from GB-South to Southern Norway

7.1.1 Generation mix

The simulation of the entire model results in the generation mix given in Figure 7.2 for Great Britain. A comparison with the actual generation mixes for 2009 and 2010, Figure 4.3 section 4.3, indicates that the share of gas in the model is much higher than the actual share while the coal is almost equivalent lower. There are several potential reasons for these deviations, such as market power, the unit's running cost and start-up cost in the model deviates from reality and differences between the unit's modelled availability and their actual availability. The most important reason is still the aggregation of plants described in section 3.1. Due to the low gas price, most of the combined cycle gas turbines (CCGT) have a lower marginal cost than the coal units. CCGT units with a slightly higher marginal cost than the cheapest coal units are aggregated with less costly CCGT plants, while the cheapest coal units are aggregated with more expensive coal units. As a result of this, CCGT capacity with a lower marginal cost than coal capacity are larger than if the units where represented individually. A simulation of Great Britain, as an isolated system, with individual representation of the plants, resulted in a 46.3 % share of gas and a 26.3 % share of coal. Some deviations from the actual shares are therefore present in the model, mostly due to the aggregation of the plants.

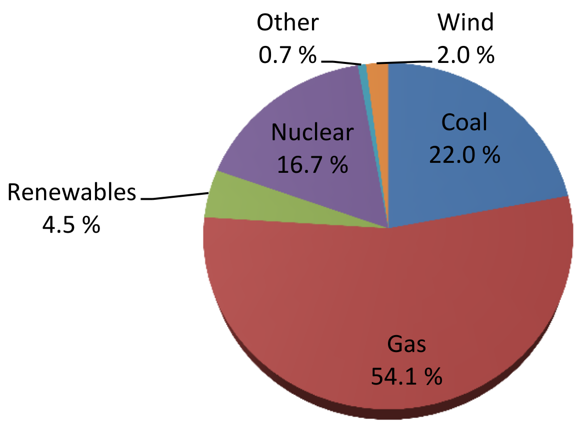

Figure 7.2: Generation mix in Great Britain based on the simulation results with real 2010 fuel prices

Nuclear and renewables plus wind are quite similar to the actual values for 2009 and 2010, while the category other is considerably lower. An overview of the average annual generation volumes and net export/imports for Great Britain calculated in the model is given in Table 7.2.

Table 7.2: Average exchange and generated volumes by source for Great Britain (TWh)

Coal	84.0
Gas	206.8
Renewables except wind	17.3
Nuclear	64.0
Other	2.9
Wind	7.7
Net import from France	3.6
Net export to Norway	5.3
Electricity generated	382.7

7.1.2 Boundary transfer within Great Britain

Simulated transfers for the three boundaries within Great Britain are given in Figure 7.3. The transferred volumes are given for each load period in sequence, meaning that load period 1 in week 1 is number 1, load period 2 week 1 is number 2 etc. Each week consists of seven load periods and the last one in the figure is period number 364, which is consistent with load period 7 week 52. A description of the seven different load periods is given in section 5.1.3.

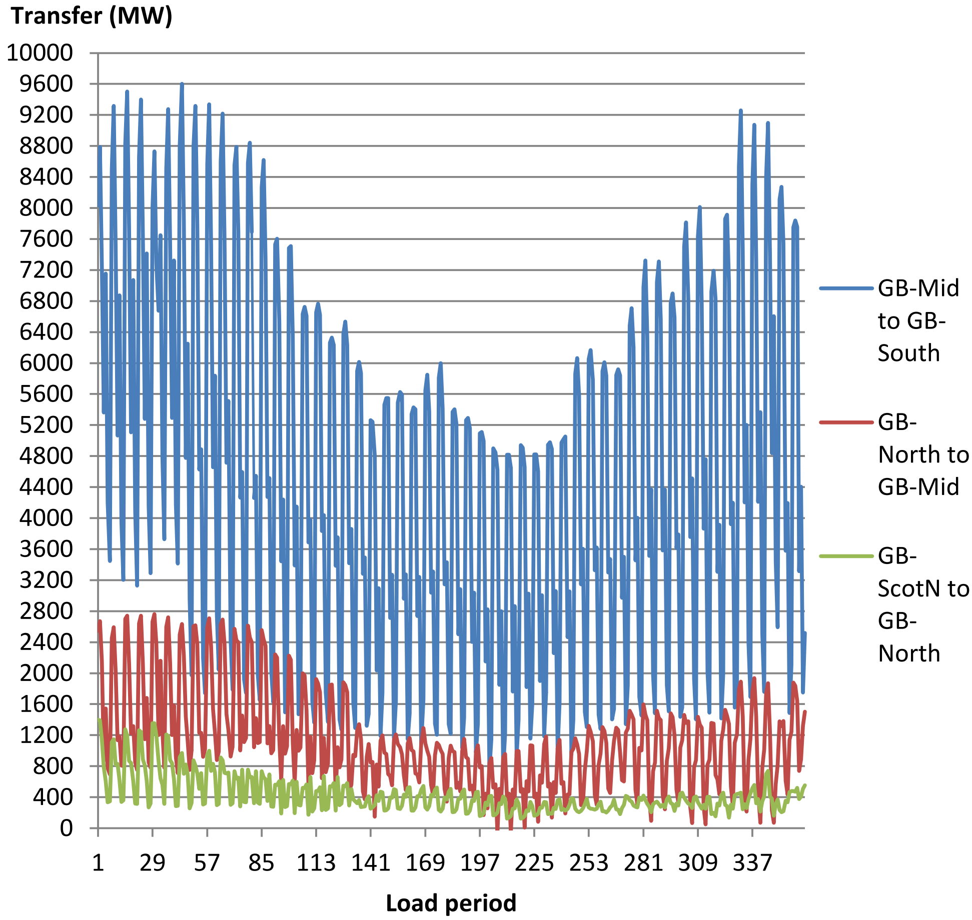

Figure 7.3: Boundary transfer within Great Britain for all load periods with normal inflow

For all three boundaries, the flow is constantly positive, meaning that the capacity is always flowing from north to south. The reason for this flow is the excess capacity in the north with a lower marginal cost than the alternative capacity in the south. The blue line in the figure is illustrating the simulated transfer across the GB-Mid – GB-South boundary for a year with normal inflow. This boundary has a capacity of 12 500 MW indicating a large excess capacity since the simulated values are considerable lower than this limit. Transmission constraints are more likely to occur across the GB-North – GB-South boundary, where the simulated transfer in peak hours is close to the boundary capacity (2 800 MW). The transferred capacity is closest to the limit during the winter since the demand to the south of the boundary is highest in this period. An illustration of the transferred capacity of each load period for the first thirteen weeks, of a normal year, is given in Figure 7.4.

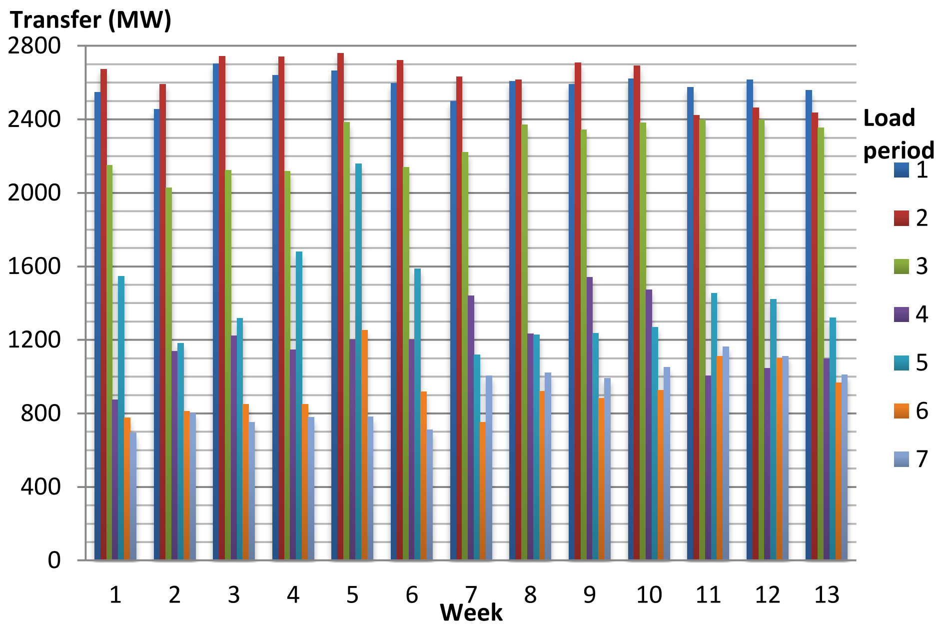

Figure 7.4: GB-North - GB-Mid boundary transfer in each of the seven load period for week 1 to 13.

Load period one (blue) and two (red), which is high load during the day and high load during the evening, respectively, are relatively close to the transfer limit. Since load periods are an aggregation of hours with similar demand, the peaks and the low points are evened out by each other. Load period one, for instance, is an aggregation of all settlement periods between 09:00 and 15:00 from Monday to Friday. Variations within this period are not allowed for in the model and it is reasonable to assume that the transfer capacity reaches the boundary's limit during some of these settlement periods. Based on this assumption, the results are in accordance with [41]which indicates large costs related to resolve constraints in Scotland and particularly at the Cheviot boundary (GB-North – GB-Mid boundary). Transferred capacity for each of the seven weekly load periods throughout a year for this boundary is given in Appendix H.

Due to the large share of hydro and wind generation capacity in Scotland, variations in inflow and wind speed also affects the transfer. An inflow scenario, close to the 90 percentile, indicates that both load period one and two reaches the boundary's capacity in five of the thirteen weeks discussed above. Transfer constraints are with that present eight hours each workday in five weeks during the winter. Since whole Great Britain is considered to be one price area in reality, the TSO would have to use the balancing mechanism to resolve these constraints. This mechanism is described in section 2.2.3.

The boundary between GB-ScotN and GB-North has a capacity of 1 600 MW. According to the results displayed in Figure 7.3, there is excess capacity throughout the entire year for this boundary. If the time resolution had been higher, some settlement periods would, most likely, have reached the transfer limit due to the large share of wind and hydro in the area.

As shown in Figure 7.3, the electricity is always flowing from north to south due to excess capacity with low marginal costs in all areas except from GB-South. An overview of the winter peak capacity flow is given in Appendix J. Annual transfer volumes across the boundaries are given in Table 7.3.

Table 7.3: Annual transfer volumes across the boundaries

Boundary	Net Transfer (TWh)
GB-Mid to GB-South	45.7
GB-North to GB-Mid	9.9
GB-ScotN to GB-North	3.8

7.1.3 Exchange between Great Britain and Southern Norway

Transfer across the HVDC link from GB-South to Nor-VestSyd depends on different prices in the two areas connected to the cable. Electricity is normally flowing from low price areas to areas with higher prices and this is also the case for this cable. In addition to prices, the flow is also dependent on the cable's transfer capacity, eventual constraint in the onshore grid and transmission losses. Transmission losses can be compared to a transfer fee for using the cable. This means that the price difference between the two areas, have to exceed this 'transfer fee' in order to make it profitable to transfer the capacity. Losses in this cable are assumed to be 4 %, indicating that the price difference has to exceed 4 %, in order to make trade across the cable profitable.

Average weekly transfer across the cable throughout a year with normal inflow is given in Figure 7.5. 40 consecutive years with historical inflow are simulated and a 'normal year' is the median year of these. As indicated in the figure, the average flow is mainly from Great Britain to Southern Norway since net export from Norway only is present in six weeks.

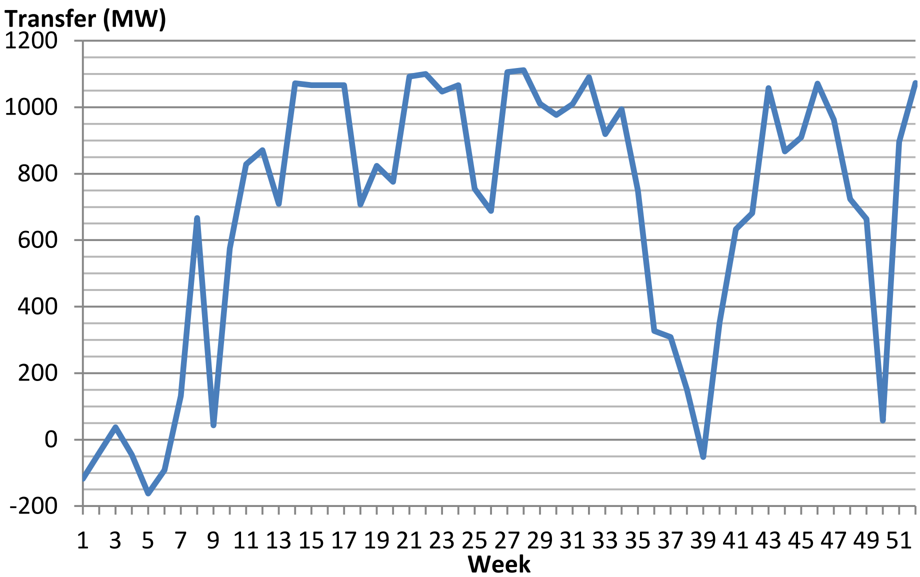

Figure 7.5: Weekly transfer from GB-South to Nor-VestSyd

In a normal year, Norway has an energy balance between the inflow and the volume of water used for generation in order to meet the demand. A cable between Norway and Great Britain, supposed that both countries were isolated from other energy systems, should have approximately zero net transfer in a normal year. The reason for the large net transfer from Great Britain must therefore be explained by the prices in the other countries within the Nord Pool area or countries connected to this area. An overview of the average weekly prices in GB-South (area 47), Denmark (area 27), Sweden (area 22) and Germany (area 31) is given in Figure 7.6. A comparison of Figure 7.5 and Figure 7.6 show that the price in GB-South is either higher or close to the highest price in weeks with negative net transfer. In the rest of the year, where the net transfer is positive, prices in GB-South are mainly lower than in the other areas. The annual export and import, for a normal year, from Great Britain to Norway are given in Table 7.4.

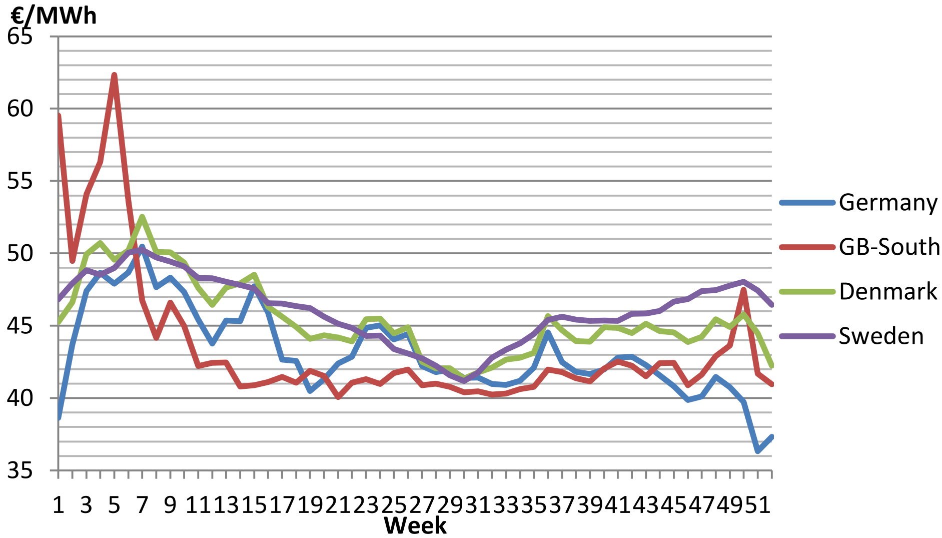

Figure 7.6: Weekly prices in Germany, GB-South, Denmark and Sweden in a normal year

Weekly flow across the cable is calculated from the transfer in each of the seven load periods. Transfer within the week may therefore vary from maximal export to maximal import even though the weekly average is positive or negative. An overview of the transfer for each load period throughout a year is given in Figure 7.7. The figure indicates that the cable flow is mainly from Norway to Great Britain in load period 1 and 2 which is 'high load during the day' and 'high load during the evening' respectively. The green line representing load period 3 ('low load during the day') is negative during the winter and positive during the rest of the year. The flow from Great Britain to Norway (positive flow), indicates that prices in load period 3 is higher in GB-South than in Nor-VestSyd during the winter and vice versa during the spring, summer and autumn. Flow in load period 4, 5, 6 and 7 is always toward Norway, indicating that the prices in these load periods are lower in GB-South than in Nor-VestSyd throughout the entire year. Load period 4, 5, 6 and 7 represents 'workday night', 'daytime Saturday and Sunday', 'Night Saturday' and 'Night Sunday' respectively. The data for the annual transferred capacities are given in Appendix I.

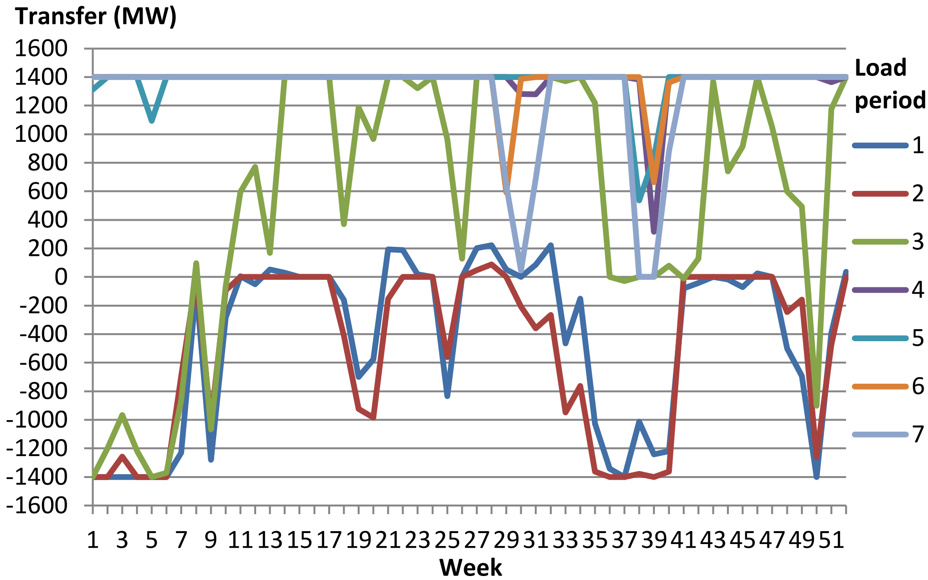

Figure 7.7: Annual transfer variations, for the seven weekly load periods, from GB-South to Nor-VestSyd for a year with normal inflow.

Prices in Norway are highly dependent on the inflow and the reservoir levels, which may vary a lot from year to year. Figure 2.3 section 2.1.4 illustrates the inflows impact on prices in Norway. Prices in a year with little inflow are normally high, yet annual average price may be lower than anticipated if the reservoir levels in the beginning of the year is high. Similarly, prices in a wet year may be higher than the inflow should require due to low reservoir levels in the beginning of the year. A wet and a dry inflow scenario are therefore chosen based on both the annual inflow and the annual average price in Norway. These two scenarios are close to the 10 and 90 percentile of the forty inflow scenarios, meaning that both a dry and a wet year occur every ten years. Imports, exports and net transfer for a wet, normal and dry year are given in Table 7.4.

Table 7.4: Transfer from GB-South to Nor-VestSyd for a wet, normal and dry year (TWh)

Transfer from GB-South	Wet year	Normal year	Dry year
Export	4.9	7.5	9.9
Import	4.0	1.5	0.9
Net export	0.9	6.0	9.0

7.1.4 Cable cost and congestion rent

Cable cost is based on cost estimates for the planned NorthConnect cable from Southern Norway to Great Britain [42]. Cost for the two 1 400 MW converter stations is assumed to be €350 million. Cable cost is assumed to be €1.8 million/km.

The proposed cable in this work from GB-South to Nor-VestSyd is approximately 850 km, resulting in a cable cost of €1530 million plus €350 million for the converter stations. Total cable cost is estimated to €1880 million.

The annual congestion rent is calculated based on the prices in each end of the cable and the transferred volumes. As mentioned previously, simulation results are based on 40 years of historical inflow. Some of these years have considerable deviations from the normal, based on the inflow's total volume and distribution through the year. The correlation between inflow and prices in a hydro-thermal system, like the Nordic, are quite strong. These variations are important for the calculation of the congestion rent. Large deviations from the normal inflow situation in Norway would normally results in larger price differences between GB-South and Nor-VestSyd. These factors are allowed for by the model and the average annual congestion rent is given as an output in the model.

The flow in the cable is always towards the area which has the highest price of the two connected areas. The owner of the cable is therefore purchasing electricity in the low price area to sell in the area with higher prices. Due to losses, the owner has to purchase additional electricity in order to deliver the required output in the other end of the cable. The model gives the average cost due to transfer losses as an output. Costs related to management and maintenance is not taken into account. The annual congestion rent, costs due to losses and the trading result is given in Table 7.5.

Table 7.5: Trading result for a cable from GB-South to Southern Norway

Congestion rent	€68.5 million
Costs due to transfer losses	€16.5 million
Trading result	**€52.3 million**

The annual cash flow is calculated to €56.3 million. Present worth for different repayment periods and discount rates, assuming constant trading result for all years, are given in Table 7.6. The discount rate is a matter of much discussion. The Norwegian Finance Ministry recommend an individual estimation of the risk premium for larger projects, such as an interconnector [43]. NVE (Norwegian Water Resources and Energy Directorate) recommend 4, 6 or 8 %, based on a 3.5 % risk free rate and a risk dependent premium of 0.5, 2.5 or 4.5 % for investments in the transmission grid including interconnectors [44]. Other estimates for the discount rate are 7 % [45] and less than 7 % [46]. For the NorNed project, recommended discount rates were 5 % [47] and 6 % [48]. Statnett have concluded that 6 % is a reasonable discount rate for such cable projects [49]. This discount rate consists of a 3.5 % risk free rate and a 2.5 % risk premium. As indicated in Table 7.6, present value is highly dependent on the chosen discount rate.

Table 7.6: Present value for a cable from GB-South to Nor-VestSyd (million euro)

	Investment repayment period (years)		
Discount rate	**20**	**30**	**40**
5 %	652	804	897
6 %	600	720	787
7 %	554	649	697

Due to the uncertain investment costs for the cable, profitability estimations for several investment costs are given in Table 7.7. The estimate is based on a 6 % discount rate and a repayment period of 40 years, giving an annuity of 0.0665.

Table 7.7: Key figures for the cable with various investment costs

Values in million €	20 % decrease	Estimated	30 % increase
Investment cost	1 504	1 880	2 444
Net present value	-786	-1 162	-1 726
Trading result	52.3	52.3	52.3
Equivalent present value	100.0	125.0	162.5
Internal rate of return	1.70 %	0.5 %	-

The net present value for all three investment costs are negative, indicating that congestion rent is not sufficient to cover the cost of the cable based on a 6 % discount rate. Equivalent present value, which is given by the investment cost multiplied with the annuity, is equivalent to the value of the trading result that would result in zero net present value. This means that the trading result, assuming original estimate for the cable, would have to be more than doubled in order to return a positive net present value. The internal rate of return on the other hand is the discount rate that would result in zero net present value. All rates are lower than the risk free estimate indicating that even without the risk premium, congestion rent would not be sufficient to cover the cost based on the current assumptions.

7.1.5 The cable's impact on the Norwegian transmission grid

The total transfer capacity from Nor-VestSyd to other Norwegian areas is 4 500 MW. Installed generation capacity in the area is approximately 6 050 MW, while the winter peak load and summer low point, in the model, are approximately 2 250 MW and 1 100 MW respectively. A 1 400 MW HVDC link from Great Britain increases the available capacity, which exceeds the boundary transfer capacity. This might lead to constraints in periods with high demand. The transfer capacities from Nor-VestSyd to the surrounding Norwegian areas are given in Table 7.8.

Table 7.8: Transfer capacities from Nor-VestSyd to other Norwegian areas

From area (area number)	To area (area number)	Transfer capacity (MW)
Nor-VestSyd (7)	Nor-Ostland (2)	900
Nor-VestSyd (7)	Nor-SorOst (3)	1 000
Nor-VestSyd (7)	Nor-Telemark (5)	900
Nor-VestSyd (7)	Nor-Sorland (6)	1 200
Nor-VestSyd (7)	Nor-VestMidt (8)	500

Especially, the boundary between Nor-VestSyd and Nor-SorOst is exposed to transmission constraints, since Nor-SorOst has a capacity deficit. In addition, some of the transfer from Nor-VestSyd to areas with higher prices, for instance Sweden, passes through this 'line' (this 'line' represents the boundary transfer between these two areas). An overview of the annual transfer for each load period across this line is given in Figure 7.8. As the figure indicates, the 'line' is operating constantly at maximum capacity from week 46 to week 12 in a normal year. Transfer in periods with high demand, like load period 1, 2 and 3, are close to or at the capacity limit during the summer also. Totally, the 'line' is operated at maximum capacity in 6571 hours per year.

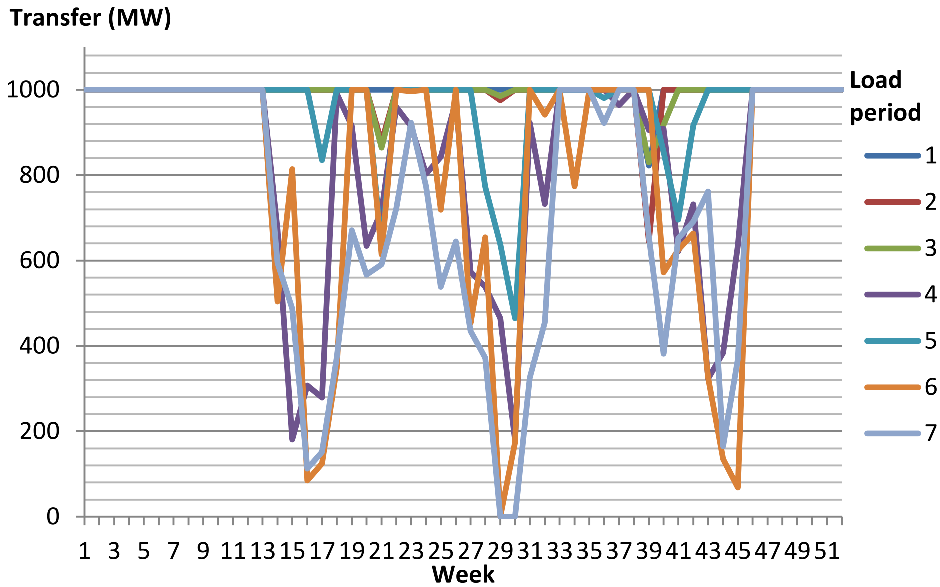

Figure 7.8: Annual Transfer variations from Nor-VestSyd to Nor-SorOst for a normal year

The boundary transfer from Nor-VestSyd and the other areas are also affected by the connection to Great Britain. An overview for the total number of hours, of which these boundaries are operated at maximum capacity, is given in Table 7.9. Transmission constraints occur across all 'lines', indicating that grid reinforcement within the Norwegian grid is recommended before constructing an interconnector to Great Britain.

Table 7.9: Number of hours of which the boundary between Nor-VestSyd and the other Norwegian areas are operated at maximal transfer capacity

Nor-VestSyd to	Wet year	Normal year	Dry year
Nor-Ostland	3 086	2 690	4 005
Nor-SorOst	5 473	6 571	5 649
Nor-Telemark	358	270	1 517
Nor-Sorland	571	322	168
Nor-VestMidt	2 288	753	838

7.2 Case 2: Link from GB-South to Southern Norway

This scenario is almost equal to the scenario described in section 7.1. Landing areas for the cable is still GB-South in Great Britain and Nor-VestSyd in Norway as shown in Figure 7.1. Transfer capacity and transmission losses for the cable are also equal to those in Case 1. The one and only difference between the two cases is the gas price in Great Britain.

Fuel price given in Table 7.1, indicates that the gas price for major power producers in Germany is 27 per cent higher than in Great Britain. Due to the low gas price, marginal costs of modern CCGT plants are lower than for coal plants in Great Britain, which is the opposite of the situation in Germany. According to the results displayed in Figure 7.6, the average electricity price in Great Britain is lower than the prices in Germany, Denmark and Sweden. Most of the price differences can be explained by the unequal gas prices. The gas price in this scenario is therefore set equal for the entire model, in order to see how an equalization of the gas price in Northern Europe would affect the transfer through an interconnector from Great Britain to Norway. It is not unreasonable to assume that the gas prices over time are equalized. Gas production on the British continental shelf are decreasing [50] resulting in increased imports which is currently 35 % of the demand. The LNG production is increasing worldwide, reducing the geographical dependency for sales and purchases. In addition, there are several promising sites across continental Europe and England with potential large volumes of natural gas tapped in shale (shale gas). An exact quantification of these elements' impact on the gas price is nearly impossible, but it is reasonable to assume that the price, to some extent, is evened out.

Fuel prices for this scenario are therefore based on data in Table 7.1 except for the gas price which is 21.6 €/MWh for both Great Britain and continental Northern Europe.

7.2.1 Generation mix

The simulated generation mix in Great Britain for this scenario is shown in Figure 7.9. A comparison of this figure and Figure 7.2 indicates that the coal and gas shares are strongly affected by the 27 per cent increase in the gas price. The share of generation from gas is decreased by 15.2 percentage points, while coal's share is increased by 14.1 percentage points. The large increase in coal's share can be explained by the unit's marginal cost. Due to the increased gas prices, coal units have lower marginal cost than the CCGT plants and their load factor is therefore increased compared to the scenario with a lower gas price. It should also be mentioned that the share of gas in Case 1 was too high due to the aggregation of plants. The same aggregation is used in this scenario, but is not affecting the shares to the same extent since most of the coal plants have a lower marginal cost than the cheapest CCGT plants.

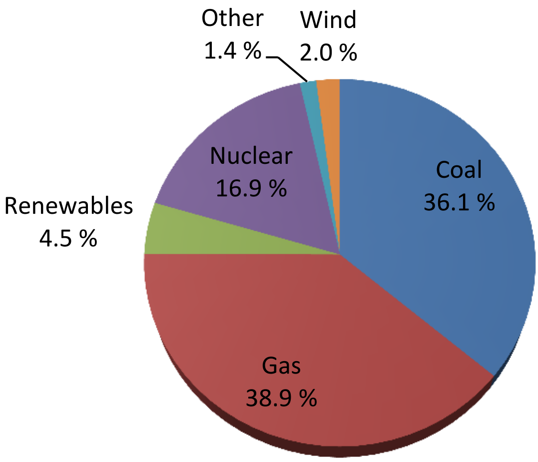

Figure 7.9: Generation mix in Great Britain with equal gas price in the model

Renewables, nuclear and wind is similar in both scenarios. There is a small increase in the 'Other' category due to more generation from pumped storage. This increase is related to a larger difference between day and night prices, making it more profitable to use pumping. Average annual values for the generated volumes by source and net export/import are given in Table 7.10.

Table 7.10: Generated volumes by source and net import/export for Great Britain (TWh)

Coal	136.4
Gas	147.0
Renewables	17.4
Nuclear	64.0
Other	5.3
Wind	7.7
Net import from France	4.2
Net export to Norway	1.0
Electricity generated	377.8

7.2.2 Boundary transfer within Great Britain

For this scenario, boundary transfer within Great Britain is quite similar to the scenario with 2010 fuel prices described in section 7.1.2 (Case 1). The exception is the GB-North – GB-Mid boundary which is facing more transfer constraints, due to the increased gas price. An overview of the transfer across this boundary for the thirteen first weeks of the year is given in Figure 7.10. Increased gas price makes it more profitable to generate electricity from coal fired plants instead of gas fired plants. Two large coal fired power plants, named Cockenzie and Longannet, are located in the GB-North area and they have an installed capacity of 1100 MW and 2300 MW respectively. These plants are therefore generating instead of more expensive CCGT plants further south. As indicated in Figure 7.10, transfer constraints are also present during low load periods, like weekends and nights. As a result of this, the boundary is operated at the limit in 612 hours per year. A comparison between this figure and Figure 7.4 show that more energy is transferred during low load periods (load period 4, 5, 6 and 7) with increased gas prices.

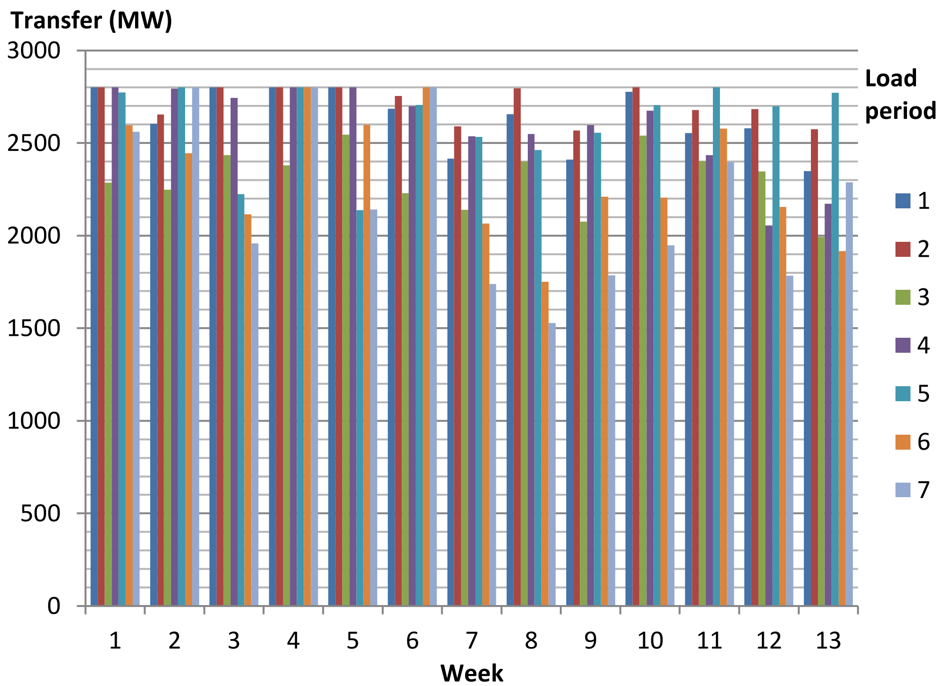

Figure 7.10: Transfer across the GB-North - GB-Mid boundary for the thirteen first weeks of a normal year

As a result of the increased transfer in most load periods, the annual transferred volume is increased. This volume and the volumes for the other two boundaries within Great Britain are given in Table 7.11.

Table 7.11: Annual boundary transfers for a scenario with increased gas price in Great Britian

Boundary	Net Transfer (TWh)
GB-Mid to GB-South	55.9
GB-North to GB-Mid	17.0
GB-ScotN to GB-North	2.6

7.2.3 Exchange between Great Britain and Southern Norway

Average weekly transfer across the cable for a normal, a dry and a wet year is given in Figure 7.11. In the first 7-8 weeks, the cable flow in all three years is towards Great Britain due to the high winter peak prices in this area. During spring the average weekly flow is towards Norway until the snow melting starts. From here, average flow in the normal year alternates from net imports to net export, while the flow in the dry year is constantly towards Norway and the flow in the wet year is constantly towards Great Britain. Annual transferred volumes are given in Table 7.12.

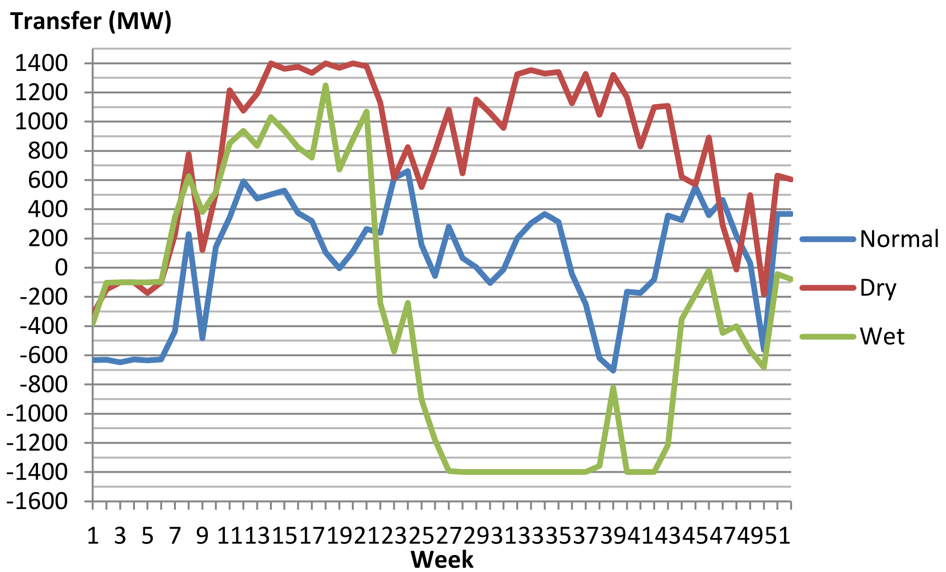

Figure 7.11: Average weekly transfer across the cable from GB-South to Nor-VestSyd for a normal, a dry and a wet year

Table 7.12: Annual transfer from GB-South to Nor-VestSyd for a wet, normal and dry year (TWh)

Transfer from GB-South	Wet year	Normal year	Dry year
Export	2.8	1.8	8.3
Import	5.6	2.3	1.1
Net export	-2.8	-0.5	7.2

The findings in section 7.1.3, with real 2010 gas prices, indicated that the weekly flow was mainly toward Norway. Similar gas prices in the entire model, on the other hand, results in a net transfer which is fluctuating around zero net transfer. Transfer across the cable is based on the price difference between the two areas. It is therefore reasonable to assume that the prices in Great Britain are more similar to the prices in the rest of the model. An overview of the prices in GB-South (area 47), Denmark (27), Sweden (22) and Germany (31) is given in Figure 7.12. The average weekly price in Great Britain is either higher or relatively close to the highest price, which is nearly the opposite of the findings for Case 1. Norway is not used as a 'transit station' for cheap British electricity on its way to Scandinavia or Continental Europe anymore.

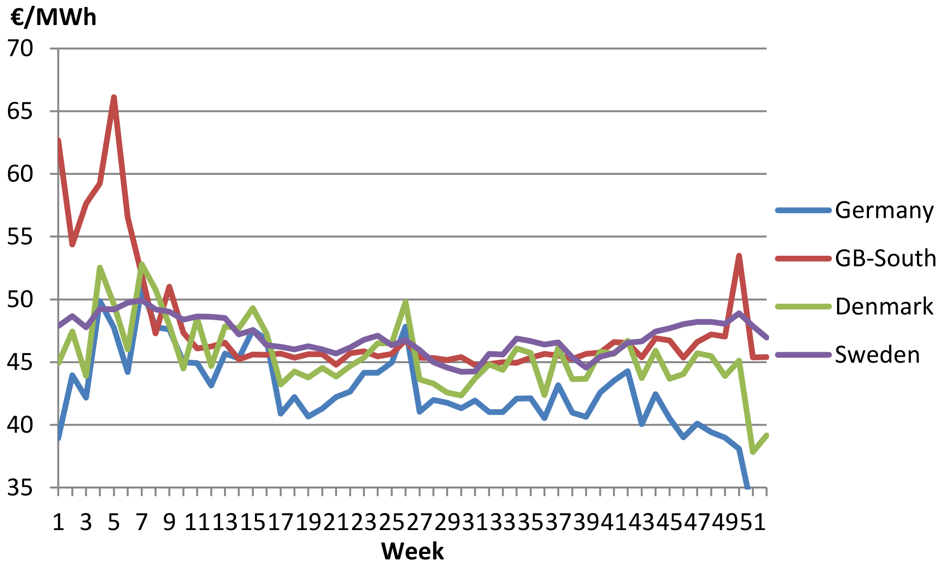

Figure 7.12: Weekly prices in Germany, GB-South, Denmark and Sweden in a normal year with equal gas price in the model

Weekly flow across the cable is calculated from the transfer in each of the seven load periods. Transfer within the week may therefore vary from maximal export to maximal import, independent of the weekly net transfer. Transfer for each load period throughout the year is given in Figure 7.13, while the corresponding values are given in Appendix K. Flow in periods with relatively high demand, like load period 1, 2 and 3, are mainly close to zero except for several weeks during the winter and the autumn when the flow is close to the capacity limit toward Great Britain. The flow during low load periods, like load period 4, 5, 6, and 7, is mainly alternating from nearly zero transfer to maximum transfer towards Norway. This indicates that prices are mainly higher in Nor-VestSyd during low load periods than in GB-South and vice versa in high load periods, except during summer when the prices are quite similar.

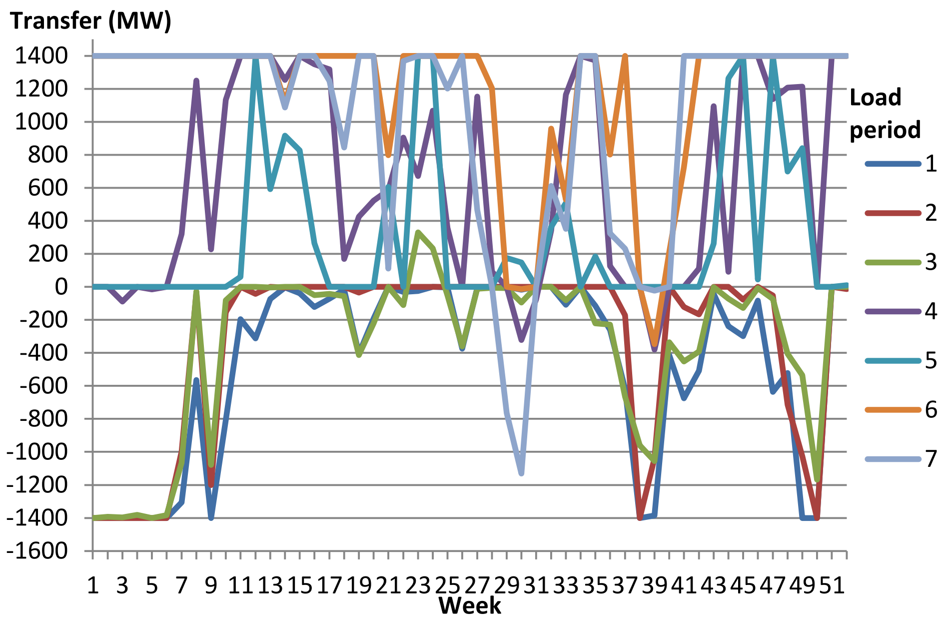

Figure 7.13: Annual transfer variations, for the seven weekly load periods, from GB-South to Nor-VestSyd for a year with normal inflow

7.2.4 Cable cost and congestion rent

Since the technical specifications for this cable are similar to the one described in section 7.1.4, the costs are also equal. Cable cost is estimated to be approximately €1880 million.

The way of calculating congestion rent and costs related to losses are described in section 7.1.4. Costs, related to management and maintenance are not taken into account. The annual congestion rent, costs due to losses and net cash flow is given in Table 7.13.

Table 7.13: Trading result for a cable from GB-South to Norway

Congestion rent	€52.8 mill
Costs due to transfer losses	€13.1 mill
Trading result	**€39.7 mill**

A comparison with the findings for Case 1 in section 7.1.4, indicates that the trading result is considerable reduced due to the equalization of electricity prices in Scandinavia and Great Britain. Both the traded volumes and the arbitrage potential are reduced, resulting in a €16.9 million reduction in trading result compared to Case 1.

Due to the uncertain investment costs for the cable, profitability estimation for several investment costs is given in Table 7.14. The estimate is based on a 6 % discount rate and a repayment period of 40 years, giving an annuity of 0.0665.

Table 7.14: Key figures for a cable with various investment costs

	20 % decrease	**Estimated**	**30 % increase**
Investment cost	1504	1880	2444
Net present value	-907	-1283	-1847
Trading result	39.7	39.7	39.7
Equivalent present value	100.016	125.02	162.526
Internal rate of return	0.3 %	-	-

The net present value for all three investment costs are negative, indicating that congestion rent is not sufficient to cover the cost of the cable based on a 6 % discount rate. The equivalent present value indicates that the trading result, assuming original estimate for the cable, would have to be more than tripled in order to return a positive net present value. Internal rate of return for the 20 % decrease scenario indicates that the discount rate would have to be 0.3 % in order to make the cable profitable based on congestion rent. For the two other scenarios, internal rate of return is negative, indicating that neither alternative would have been profitable with a positive discount rate.

7.2.5 The cable's impact on the Norwegian transmission grid

Transfer capacities from Nor-VestSyd to the other Norwegian areas are given in Table 7.8 section 7.1.5. Total transfer capacity from Nor-VestSyd is 4 500 MW in addition to the 1 400 MW cable towards Great Britain. Normally, generation exceed the demand in Nor-VestSyd considerably and excess capacity is transferred toward deficit areas with higher prices. Similarly to Case 1, the boundary between Nor-VestSyd and Nor-SorOst is exposed to transmission constraints. Weekly average transfer throughout a year with normal inflow is given in Figure 7.14. The transfer capacity across this boundary is 1 000 MW and the figure indicates that the boundary is constantly operated at maximum capacity during the winter. These results are similar to the findings in Case 1 where the boundary was operated constantly at maximum capacity from week 46 to week 12 for the same inflow scenario. Transfer during the rest of the year, especially during spring time, is reduced. The explanation is that Nor-SorOst is not used as a 'transit area' for electricity transfer towards areas with higher prices to the same extent in this scenario.

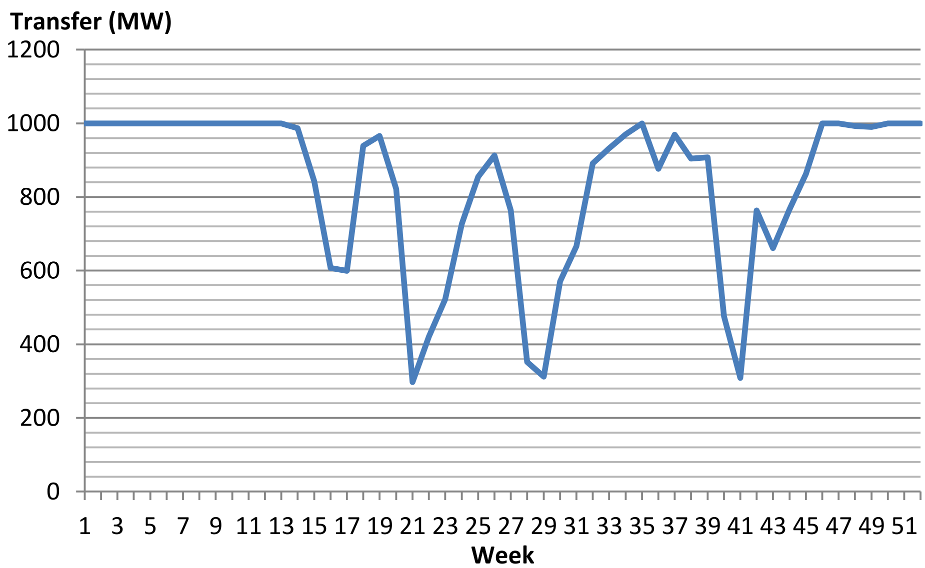

Figure 7.14: Average weekly transfer from Nor-VestSyd to Nor-SorOst in a year with normal inflow

The number of hours of which the boundary is operated at the limit is brought down. This is due to the reduced transfer from Great Britain, which reduces the transfer from Nor-VestSyd to the other Norwegian areas. A lower net import is also affecting the number of hours the other boundaries are operated at maximal transfer capacity. Constraints towards Nor-Ostland, Nor-SorOst and Nor-Telemark are reduced while there are an increase towards Nor-Sorland and Nor-VestMidt. Each boundary's annual portion of operation at the capacity limit is given in Table 7.15.

Table 7.15: Number of hours of which the boundary between Nor-VestSyd and other Norwegian areas are operated at maximal transfer capacity

Nor-VestSyd to	Normal year	Dry year	Wet year
Nor-Ostland	1190	3966	2260
Nor-SorOst	5577	5483	5071
Nor-Telemark	280	338	100
Nor-Sorland	532	259	1275
Nor-VestMidt	1584	958	2083

7.3 Case 3: HVDC link between GB-ScotN and Southern Norway

A subsea HVDC cable is connecting GB-ScotN (area 50) and Nor-VestSyd (area 7) as illustrated by the red line in Figure 7.15. Transfer capacity for the cable is set to 1 400 MW, in both directions, while transmission losses are assumed to be 4 %. Fuel prices are equal to the prices in Table 7.1. The simulated generation mix in Great Britain is equal the one found in Case 1. An overview of the generation shares is given in Figure 7.2 section 7.1.1.

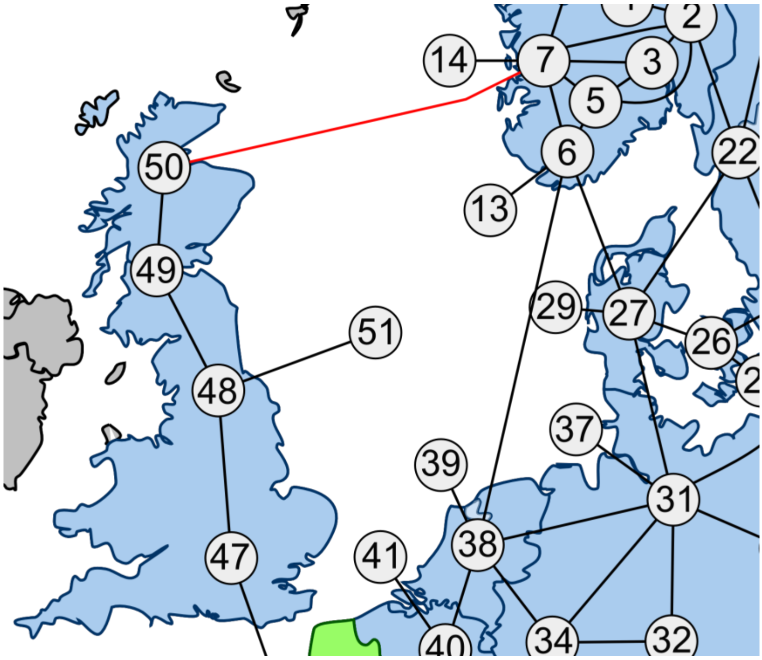

Figure 7.15: HVDC link from GB-ScotN to Southern Norway

7.3.1 Boundary transfer within Great Britain

Transfer across the boundaries within Great Britain is shown in Figure 7.16. The GB-Mid - GB-South boundary is not facing any constraints since the transfer in all load periods are below 12 500 MW, which is the maximal transfer capacity. It should also be noted that the average transfer is approximately 1 000 MW lower than the transfer in Case 1 with a cable from GB-South to Norway (See Figure 7.3 in section 7.1.2). On the other hand the peak transfer during winter is higher for this case. Transfer through the Norwegian interconnector in Case 1 was mainly towards Norway except in peak hours during the winter. This explains the differences since capacity in

Case 1 was transferred from GB-Mid to Norway via GB-South during most of the year except for the winter peaks when GB-South was importing from Norway. Both the GB-North – GB-Mid and GB-ScotN – GB-North boundaries are operated at the capacity limit especially during the winter. Their capacity limits are 2 800 MW and 1 600 MW respectively.

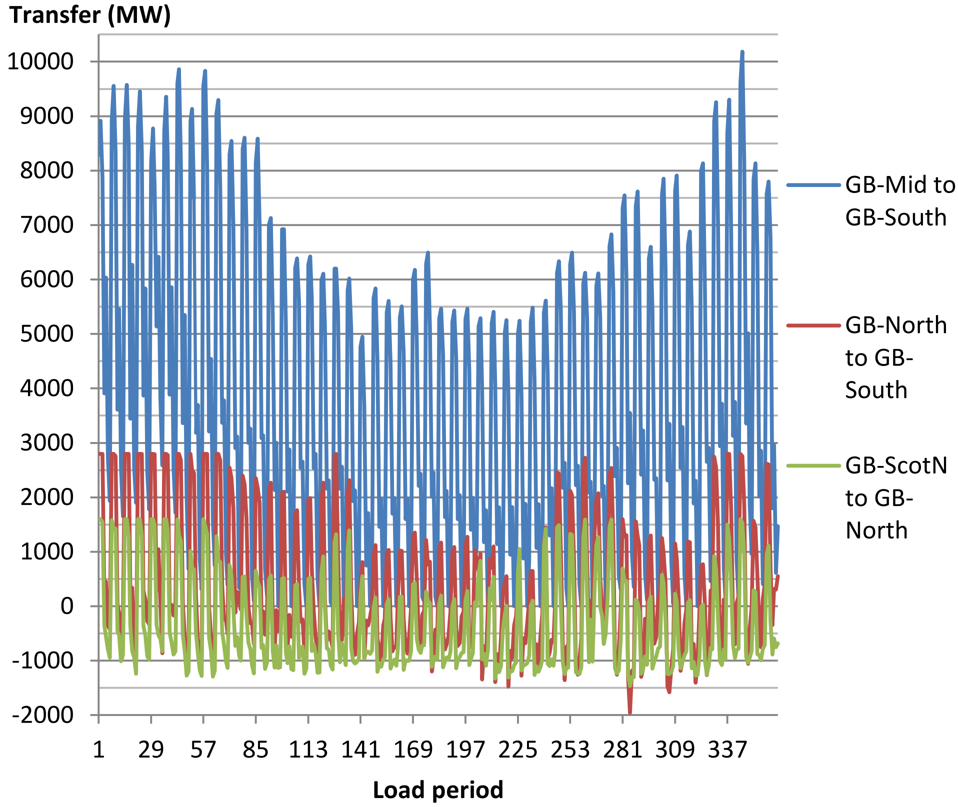

Figure 7.16: Transfer across the boundaries within Great Britain

7.3.1.1 GB-North – GB-Mid and GB-ScotN – GB-North boundaries

As indicated in Figure 7.16, the boundary between GB-North and GB-Mid is exposed to transfer constraints due the interconnector to Norway, which is increasing the transfer across the boundary in certain load periods. An overview of the transfer across the boundary for each load period is given in Figure 7.17. As indicated in the figure, transfer across the boundary is highest in load periods which have the highest demand (load period 1, 2 and 3). In periods with low demand (load period 4, 5, 6 and 7) are the transfer mainly reversed, due to transfer towards Norway. This is in great contrast to the flow across this boundary in Case 1, where the transfer across the boundary always was towards GB-Mid. A link to Norway, connected to Great Britain in Scotland, would therefore alter the nearly constant North – South capacity flow which is present in today's system.

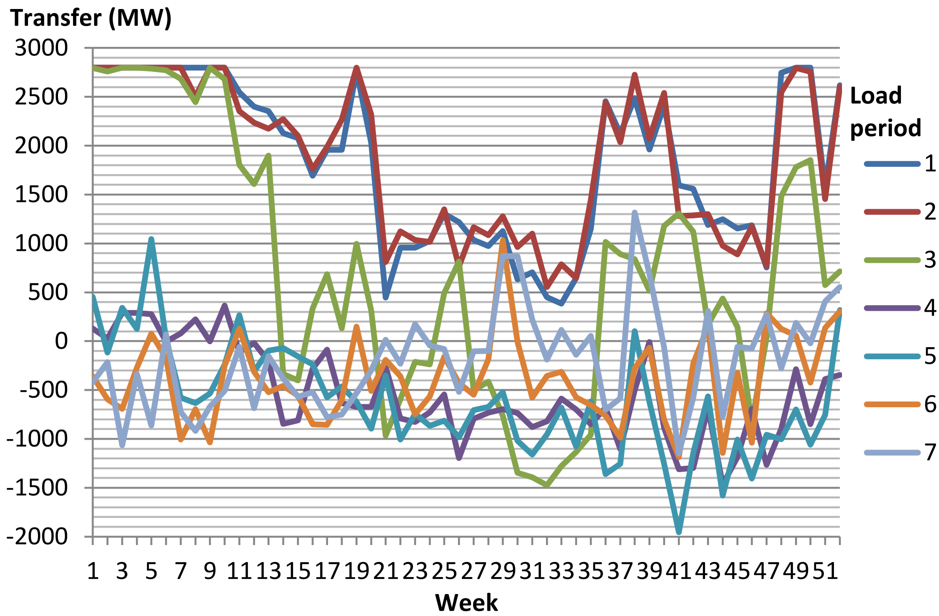

Figure 7.17: Transfer across the GB-North - GB-Mid boundary for each load period in a normal year

Transfer for each load period across the GB-ScotN – GB-North boundary is quite similar to the shapes in Figure 7.17 for the GB-North – GB-Mid boundary. The difference is related to the transfer's magnitude. Transfer in high load periods is lower while low load periods have an increased import to GB-ScotN from GB-North (increased negative transfer).

Transfer across these boundaries is affected by the variations in inflow, especially in Norway, due to the inflow's influence on the transfer through the cable. Transfer for the GB-North - GB-Mid boundary for a wet and a dry year are given in Figure 7.18 and Figure 7.19 respectively. A wet year increases the number of hours of which the boundary is operated at maximal capacity during high load periods. There is also an increase for low load periods and during summer. Transfer across the boundary is larger for these periods than for the periods with high demand. This can be explained by the varying demand in Scotland and the marginal cost of the imported volumes. Since GB-ScotN is constantly importing through the cable the excess capacity during low load periods in Scotland is larger than for high load periods. Additionally, the imported volumes have a lower marginal cost than the generation within Scotland. Together these factors result in a higher export to GB-Mid for low load periods during July and August.

For a dry year the transmission constraints are considerable reduced since they normally are related to high export to GB-Mid. A large portion of the generated energy in Scotland is transferred to Norway, resulting in less export to GB-Mid.

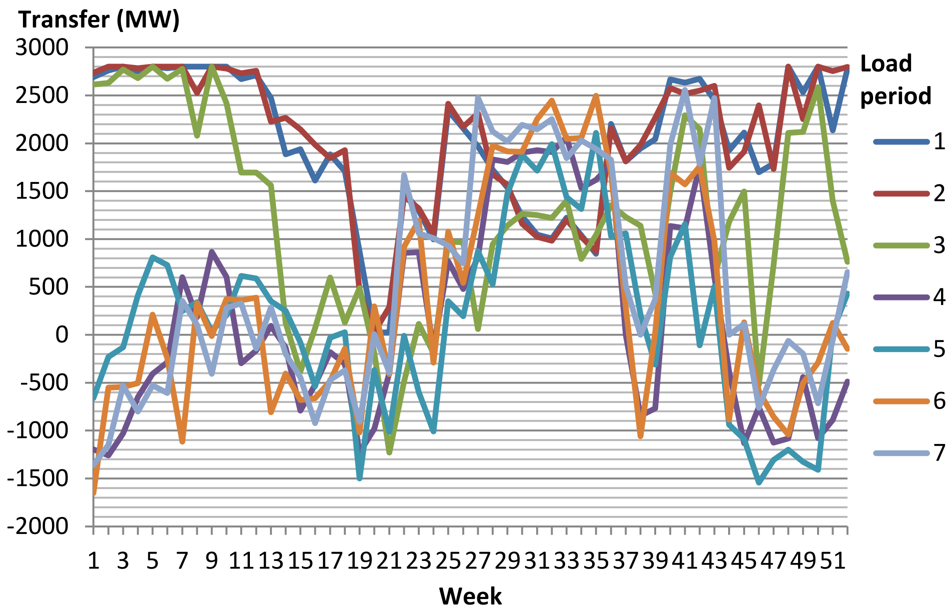

Figure 7.18: Transfer across the GB-North - GB-Mid boundary for each load period in a wet year

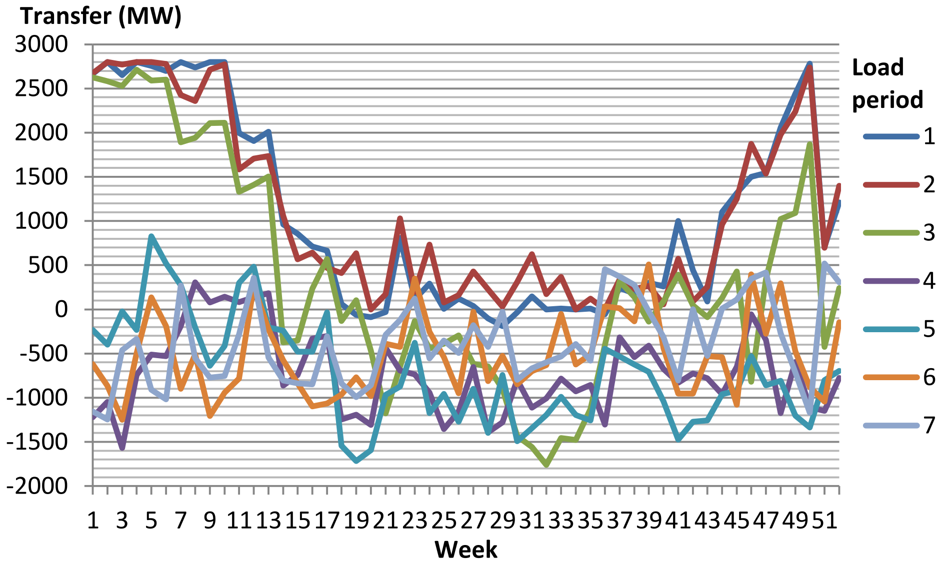

Figure 7.19: Transfer across the GB-North - GB-Mid boundary for each load period in a dry year

Annual numbers of hours that the boundaries are operated at maximal capacity is given in Table 7.16. Constraints are present at the GB-North – GB-Mid boundary in more than 6 % of the year if a cable are connected to Scotland, indicating that grid reinforcements are required in order to reduce costs related to eventual countertrade.

Table 7.16: Number of hours of which the boundaries within Great Britain are operated at maximal transfer capacity

Boundary	Wet year	Normal year	Dry year
GB-Mid – GB-South	0	0	0
GB-North – GB-Mid	280	550	170
GB-ScotN – GB-North	809	230	320

7.3.2 Exchange between Great Britain and Southern Norway

Average weekly transfer across the cable is given in Figure 7.20. Weekly transfer for this case is quite similar to the transfer in Case 1 (Figure 7.11 section 7.1.3). There are still some deviations, especially from week 1 to week 7, when the net weekly transfer is towards Norway in this case while it mainly was towards Great Britain in Case 1. This difference can be explained by the difference in winter peak prices in GB-South and GB-ScotN. Prices in GB-South exceeds the prices in Nor-VestSyd during load period 1, 2 and 3 resulting in a net transfer to GB-South in these weeks. A similar price difference is present in GB-ScotN, but the transfer constraints, in high load periods, on the GB-ScotN – GB-North boundary is reducing the imports from Norway, resulting in a net positive weekly transfer to Norway for these weeks. Transfer for each load period is similar to the findings in Figure 7.13 for Case 1.

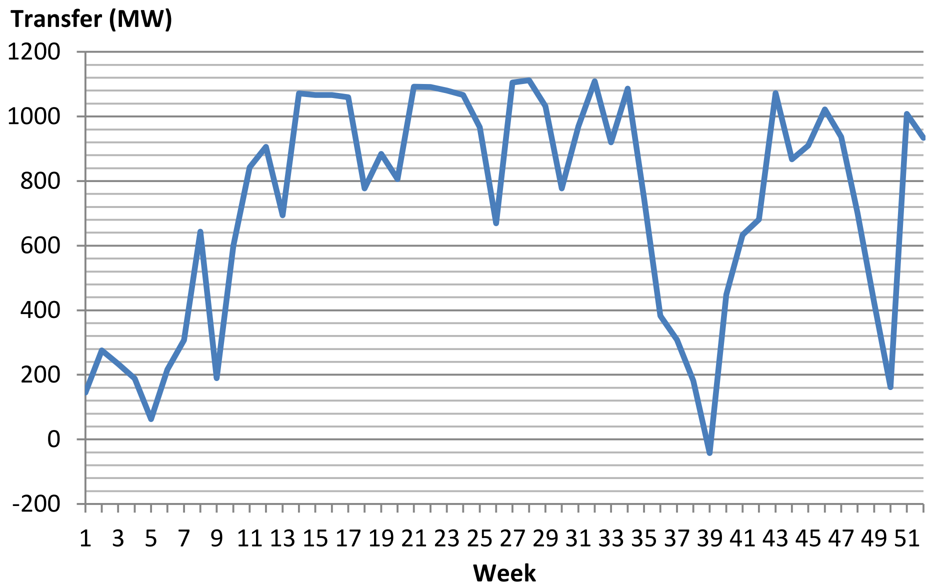

Figure 7.20: Average weekly transfer from GB-ScotN to Nor-VestSyd

Annual transferred volumes across the cable are given in Table 7.17 for a wet, a normal and a dry year. A comparison with the transferred volumes for Case 1 (Table 7.4), indicates that the cable's area of connection in Great Britain, hardly is affecting the transferred volumes. The exception is the reduced import during a wet year, which can be explained by the constraints discussed previously.

Table 7.17: Annual transfer from GB-South to Nor-VestSyd for a wet, normal and dry year (TWh)

Transfer from GB-South	Wet year	Normal year	Dry year
Export	4.9	7.5	10.0
Import	3.7	1.1	0.7
Net export	1.2	6.4	9.3

7.3.3 Cable cost and congestion rent

The proposed cable from GB-ScotN to Nor-VestSyd is approximately 560 km. Cost for the cable is calculated to €1 008 million based on the €1.8 million/km cost estimate. Total cable cost is calculated to €1 358 million, including €350 million for the converter stations.

The annual congestion rent, costs due to losses and trading result for the cable from GB-ScotN to Nor-VestSyd are given in Table 7.18. The way of calculating congestion rent and costs related to losses are described in section 7.1.4.

Table 7.18: Trading result for a cable from GB-ScotN to Norway

Congestion rent	€53.2 mill
Costs due to transfer losses	€15.6 mill
Trading result	**€37.6 mill**

A comparison with the findings for Case 1, in section 7.1.4, indicates that the trading result is decreased. The congestion rent is reduced, due to less transferred volumes across the cable, in addition to an equalization of the prices between Nor-VestSyd and GB-ScotN in periods with transfer constraints at the GB-ScotN – GB-North boundary. In periods with export to Norway, constraints are reducing the capacity available for transfer in the GB-ScotN area. More expensive units in the GB-ScotN are started in order to reach the cable's capacity limit until the price in GB-ScotN plus the cost of losses exceed the price in Nor-VestSyd. A similar argument would be valid for flow towards GB-ScotN, resulting in lower price in this area. Less price differences across the cable in addition to less transferred volume, reduces the congestion rent.

Due to the uncertain investment costs for the cable, profitability estimations for several investment costs are given in Table 7.19. The estimate is based on a 6 % discount rate and a repayment period of 40 years, giving an annuity of 0.0665.

Table 7.19: Key figures for a cable with various investment costs

	20 % decrease	Estimated	30 % increase
Investment cost	1086.4	1358	1765.4
Net present value	-520.4	-792	-1199.4
Trading result	37.6	37.6	37.6
Equivalent present value	72.2456	90.307	117.3991
Internal rate of return	1.70 %	0.50 %	-

The net present value for all three investment costs are negative, indicating that congestion rent is not sufficient to cover the cost of the cable based on a 6 % discount rate. The equivalent present value indicates that the trading result, assuming original estimate for the cable, would have to be more than doubled in order to return a positive net present value. Internal rate of return for both the 20 % decrease scenario and the original estimate are positive. Nevertheless, both rates are less than the 3.5 % risk free rate, indicating that even without the risk premium none of these investment costs would have been profitable based on the congestion rent alone.

A comparison of the net present values for Case 1 and Case 3, prove that the financial loss for a cable from GB-ScotN to Nor-VestSyd is less than for the cable from GB-South to Nor-VestSyd. What this numbers does not say is the costs for constraint handling and reinforcement in the main grid caused by the cable's landing area. The findings in section 7.3.1.1 indicate that grid reinforcement is required, at both the GB-ScotN – GB-North and GB-North – GB-Mid boundary, if the cable from Norway is connected to GB-ScotN. Deciding which cable alternative is less costly or has least financial loss, taken both direct and indirect costs into consideration, is therefore not possible based on the data discussed above.

7.3.4 The cable's impact on the Norwegian transmission grid

The cable's impact on the Norwegian transmission grid is quite similar to the findings for Case 1 in section 7.1.5. Both the transferred volumes and the transfer pattern are almost equal in both cases and the discussion in that section is therefore also valid for this case.

8 EMPS simulations for the 2020 scenario

All simulations are carried out based on the areas and connections illustrated in Figure 6.2 section 6.1 including the different cable alternatives between Great Britain and Norway. Fuel prices are equal in all countries in the model. An overview of the fuel prices are given in Table 8.1.

Table 8.1: Fuel prices for the 2020 scenario

Fuel	Price €/MWh
Coal	9.8
Gas	21.6
Oil	57.5

Three different cases are discussed in this chapter. Case 4 includes a cable from Southern England to Southern Norway. The cable's capacity is set to 1 400 MW and the fuel costs in the model are given in the previous table.

Case 5 and Case 6 includes a cable from Southern Norway to Dogger Bank. In both cases the transfer capacity are 1 400 MW and the only difference is the transfer capacity from Dogger Bank to Great Britain. In Case 5, this capacity is set equal to the installed capacity (3 600 MW) of the wind farm at Dogger Bank. The transfer capacity in Case 6 is set to 2 200 MW in such a way that the installed capacity at Dogger Bank equals the sum of the transfer capacity to Norway and Great Britain. Prices in both cases are equal to those given in the previous table.

The results are presented for either for a wet, normal, dry year or for all three. If the type of year is not specified, the results are presented for a normal year. A short explanation of the various types of years is given in section 0.

8.1 Case 4: HVDC link between GB-South and Southern Norway

A HVDC cable is connecting GB-South (area 47) to Nor-VestSyd (area 7) as illustrated in Figure 8.1. The transfer capacity is set to 1 400 MW for both directions, while transmission losses in the cable are assumed to be 4 %. Fuel prices are equal to the prices given in Table 8.1. For the 2020 scenario the gas price in Germany and Great Britain is equal. This is an assumption based on the discussion in section 7.2 about the present changes in the gas market and possible future developments that might affect the gas price in Europe.

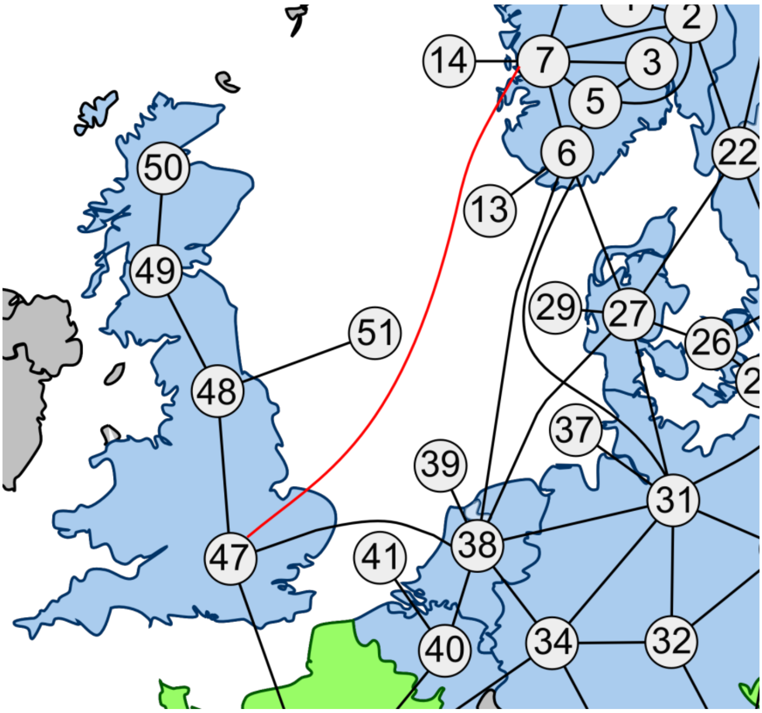

Figure 8.1: HVDC cable from GB-South to Nor-VestSyd for the 2020 scenario

8.1.1 Generation mix

The generation mix in Great Britain for the 2020 scenario is given in Figure 8.2. Wind and renewables are the categories with the largest increase from the 2010 scenario. Wind includes both onshore and offshore generation, such as Dogger Bank. The large increase in renewables is mostly due to new power plants running on biofuels.

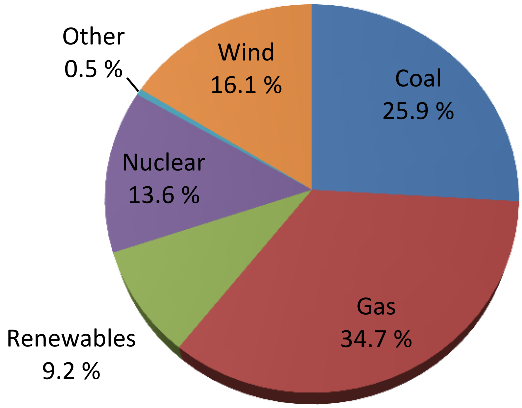

Figure 8.2: Generation mix in Great Britain for a 2020 scenario

There is also a reduction in nuclear, coal and gas generation. Nuclear is reduced due to the reduction in generation capacity, while the reduced generation from coal is a result of less installed capacity. Installed capacity for gas plants are slightly increased compared to the 2010 scenario even though the generated volume from gas is reduced. This indicates that the hours of operation is considerable reduced for some of the gas fired plants with the highest marginal costs. An overview of the average annual values for generated volumes and net export/import for Great Britain is given in Table 8.2.

Table 8.2: Generated volumes by source and net import/export for Great Britain (TWh)

Coal	93.5
Gas	125.1
Renewables	33.0
Nuclear	48.9
Other	1.9
Wind	58.0
Net export to France	0.8
Net import from Norway	8.1
Net import from The Netherlands	2.6
Electricity generated	360.4

8.1.2 Boundary transfer within Great Britain

Transfer across the boundaries, for each load period, throughout a year is given in Figure 8.3. Compared to the findings in Case 1 for the 2010 scenario (Figure 7.3 section7.1.2), transfer variations are much more volatile in the 2020 scenario, especially for the GB-North – GB-Mid boundary. This can be explained by the large portion of wind capacity located in Scotland, which have a varying generation. The fact that the same wind series is used for all wind farms, independent of their location within Great Britain, increases this volatility. Wind farms located in different areas are therefore not able to even out the fluctuations in the model since the model does not allow for varying wind conditions at different sites.

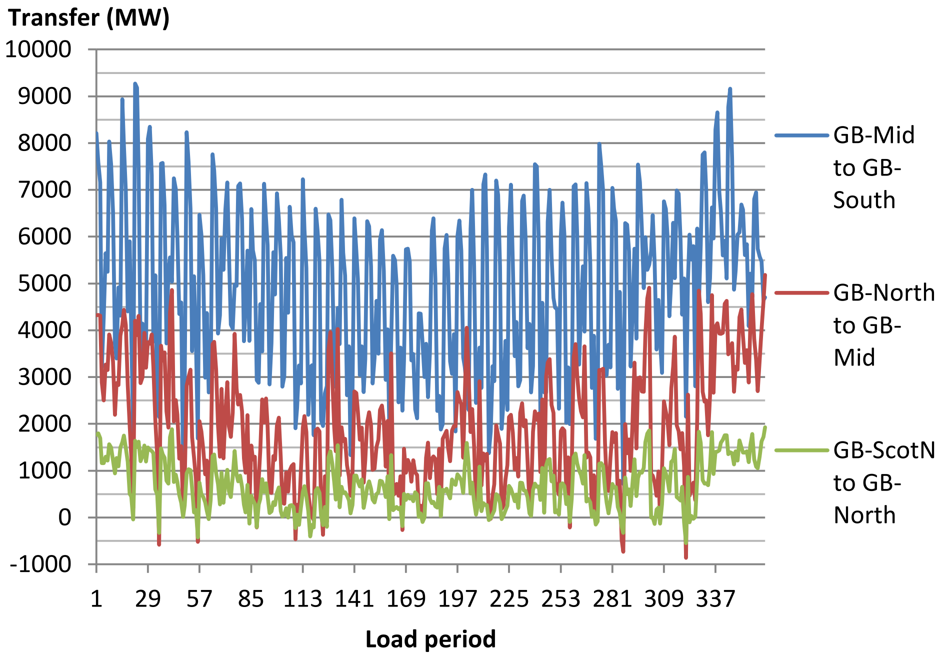

Figure 8.3: Boundary transfer within Great Britain for all load periods in a normal year

The transfer capacity across the GB-Mid – GB-South boundary is 11 500 MW, while the highest transfer for a normal year is approximately 9 200 MW. Neither the GB-North – GB-Mid nor the GB-ScotN - GB-North boundaries are facing any constraints during a normal year. Their transfer capacities are 5 800 MW and 2 650 MW respectively. As mentioned previously in the report, the model's resolution time is reducing most of the spikes and some constraints could have been present in a model with higher time resolution. The second factor is the uncertainty related to the quantity of installed wind capacity in Scotland. A 1 000 MW increase in the installed capacity north of the GB-North – GB-Mid boundary could result in transfer constraints for this boundary in certain load periods throughout the year.

Annual transfers, in a normal year, across the boundaries are given in Table 8.3. Transfer from Scotland is almost doubled compared to the 2010 scenario in Case 1 (Table 7.3 section 7.1.2) due to the large portion of wind capacity located in Scotland. The present situation where capacity is mainly flowing from North to South is therefore going to be further enhanced towards 2020 based on these results.

Table 8.3: Annual transfer volumes across the boundaries

Boundary	Net Transfer (TWh)
GB-Mid to GB-South	44.8
GB-North to GB-Mid	17.3
GB-ScotN to GB-North	5.8

8.1.3 Exchange between Great Britain and Norway

As for the generation capacity in Great Britain, generation capacity in Norway is assumed to increase towards 2020 also. This is mainly related to an increase in wind capacity and many new small hydro-electric power stations. Presently, Norway is self-sufficient with electricity in a year with normal inflow. Since the demand is assumed to remain relatively constant towards 2020 while the generation is increasing, Norway is expected to have both excess capacity and energy. The marginal cost of the excess volumes from hydro and wind would be lower than the marginal cost for the thermal plants in the neighbouring countries due to the method of calculation for the water values. Norway is therefore a net exporter for a normal year in the 2020 scenario. An overview of the weekly transfer across the cable from GB-South to Nor-VestSyd for a normal year is given in Figure 8.4. According to the figure, average weekly flow is always towards Great Britain and the volumes are greatest during the winter when prices in Britain are highest.

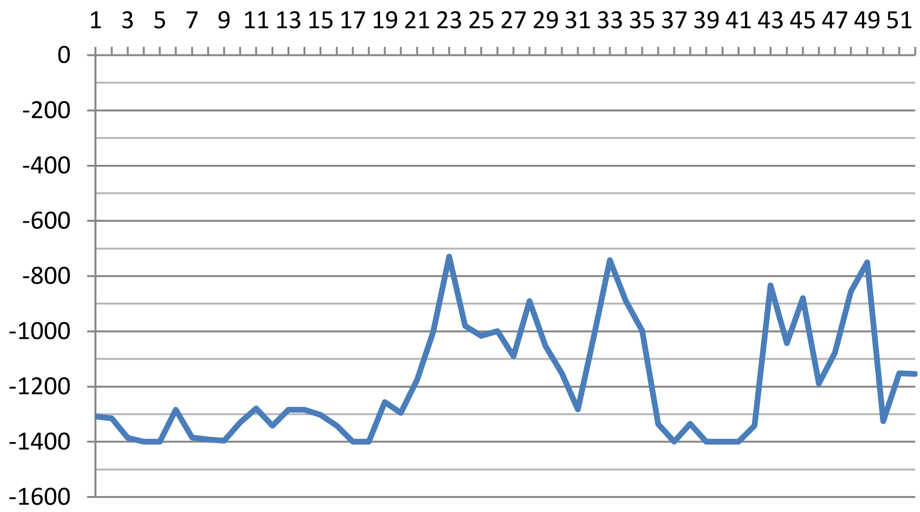

Figure 8.4: Weekly transfer from GB-South to Nor-VestSyd

Weekly flow across the cable is calculated from the transfer in each of the seven load periods. Transfer within the week may therefore vary even though the weekly average is negative. An overview of the transfer for each load period throughout a year is displayed in Figure 8.5.

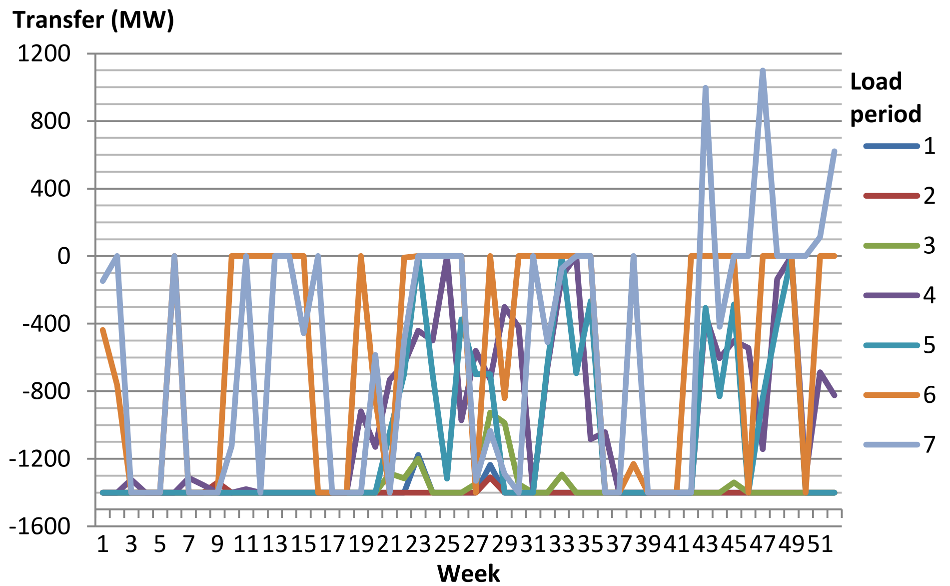

Figure 8.5: Annual transfer across the cable from GB-South to Nor-VestSyd for each load period

Transfer in high load periods during workdays, such as load period 1, 2 and 3, is nearly without exception at the cable's capacity limit. In periods with less demand, like workday night and daytime during the weekend (4 and 5 respectively), the cable is operated at maximum capacity during the winter and spring while the transfer is reduced but still negative during the summer and some of the autumn. Load periods 6 and 7, representing night Saturday and night Sunday, are varying mainly from zero to maximal export towards Britain throughout the year.

Imports, exports and net transfer for a wet, a normal and a dry year are given in Table 8.4. Maximal feasible transfer volume across a 1 400 MW cable within a year is 12.3 TWh. The cable is working close to this limit in both normal years and in wet years due to the large energy surplus in these years. According to the table, import to GB-South is larger during a normal year than a wet year. This is due to a lower reservoir level in the beginning of the historical year representing a wet year than the normal year, resulting in higher prices towards the summer in the wet scenario. Therefore, it is a small decrease in transfer from Norway towards Great Britain and even some imports in the low load periods during the spring. Even though the inflow in the wet scenario exceeds the normal one, the transfer is limited by the cable's capacity from the snow starts to melt and onwards resulting in less transferred volume in the wet year.

Table 8.4: Annual transfer from GB-South to Nor-VestSyd for a wet, normal and dry year (TWh)

Transfer from GB-South	Wet year	Normal year	Dry year
Export	0.05	0.02	0.65
Import	9.67	9.97	4.97
Net export	-9.12	-9.95	-4.32

8.1.4 Cable cost and congestion rent

Cable cost is based on cost estimates for the planned NorthConnect cable from Southern Norway to Great Britain [42]. Cost for the two 1 400 MW converter stations is assumed to be €350 million. Cable cost is assumed to be €1.8 million/km.

The proposed cable from GB-South to Nor-VestSyd is approximately 850 km, resulting in a cable cost of €1 530 million plus €350 million for the converter stations. Total cable cost is estimated to €1 880 million.

The annual congestion rent, costs due to losses and trading result for the cable from GB-ScotN to Nor-VestSyd is given in Table 8.5. The way of calculating congestion rent and costs related to losses are described in section 7.1.4.

Table 8.5: Trading result for a cable from GB-South to Norway

Congestion rent	€56.0 mill
Costs due to transfer losses	€13.2 mill
Trading result	**€40.8 mill**

This is a €19 million reduction in trading result compared to the result for Case 1. This can be explained by the reduced price variations in both Norway and Great Britain. Prices in Norway are evened out since Norway has an energy surplus also during relative dry years, which reduces the price variations from year to year. The large increase in wind capacity in Great Britain at the same time as the thermal capacity is kept nearly constant in order to secure a stable output in case of calm air, results in much more capacity in the system than required most of the time. The system is therefore not exposed to outages and peak loads to the same extent as in the 2010 scenario in Case 1.

Due to the uncertain investment costs for the cable, profitability estimation for several investment costs is given in Table 8.6. The estimate is based on a 6 % discount rate and a repayment period of 40 years, giving an annuity of 0.0665.

Table 8.6: Key figures for a cable with various investment costs

Million €	20 % decrease	Estimated	30 % increase
Investment cost	1504	1880	2444
Net present value	-890	-1266	-1830
Trading result	40.8	40.8	40.8
Equivalent present value	100.0	125.0	162.5
Internal rate of return	0.4 %	-	-

The net present value for all three investment costs are negative, indicating that congestion rent is not sufficient to cover the cable cost based on a 6 %

discount rate. Equivalent present value indicates that the trading result would have to be more than tripled in order to make the cable profitable for on the original cost estimate and a 6 % discount rate. Both the 20 % decrease estimate and the original estimate have a positive internal rate of return, but both rates are below the risk free rate of 3.5 %. None of the estimates are therefore profitable based on the trading result alone.

8.1.5 The cable's impact on the Norwegian transmission grid

Total transfer capacity from Nor-VestSyd to the other Norwegian areas is 4 500 MW, which is the same capacity as for the 2010 scenario. Presently, Nor-VestSyd has both energy and capacity surplus and this surplus are further increased in the 2020 scenario due to new hydro power plants and wind farms. More energy is therefore exported from the area and the boundary transfer capacities are given in Table 8.7.

Table 8.7: Transfer capacities from Nor-VestSyd to other Norwegian areas for the 2020 scenario

From area (area number)	To area (area number)	Transfer capacity (MW)
Nor-VestSyd (7)	Nor-Ostland (2)	900
Nor-VestSyd (7)	Nor-SorOst (3)	1000
Nor-VestSyd (7)	Nor-Telemark (5)	900
Nor-VestSyd (7)	Nor-Sorland (6)	1200
Nor-VestSyd (7)	Nor-VestMidt (8)	500

The number of hours these boundaries are operated at their maximal capacity is displayed in Table 8.8. Transfer from Nor-VestSyd to Nor-VestMidt is at the boundary in 86 % of a normal year indicating that grid reinforcement is required. Flow is mainly towards Nor-VestSyd since Nor-VestMidt is a surplus area due to a large increase in the installed wind capacity and some new hydro. The model does not include the planned overhead line between Fardal and Ørskog and the line from Modalen to Kollsnes via Mongstad, which would have increased the capacity considerable and potentially removed the constraints during most of the year. Constraints toward Nor-Ostland and Nor-SorOst are reduced compared to the findings in Case 1 since there is less import to these areas from Nor-VestSyd due to excess capacity in other surrounding areas. Transfer constraints towards Nor-Sorland on the other hand are increased due to the rise in transfer capacity towards Denmark and

Germany from this area, resulting in more export or import to Nor-Sorland from the surrounding Norwegian areas.

Table 8.8: Number of hours that the boundary between Nor-VestSyd and other Norwegian areas are operated at maximal transfer capacity

Nor-VestSyd to	Normal year	Dry year	Wet year
Nor-Ostland	265	1001	1136
Nor-SorOst	1143	3268	2077
Nor-Telemark	0	100	0
Nor-Sorland	1642	801	1476
Nor-VestMidt	7572	3674	6424

8.2 Case 5: HVDC link from Dogger Bank to Southern Norway

A HVDC cable is connected between Dogger Bank (area 51) and Nor-VestSyd (area 7) as illustrated in Figure 8.6. The transfer capacity is set to 1 400 MW for both directions, while transmission losses in the cable are assumed to be 3 %. Transfer capacity for the cable from Dogger Bank to GB-Mid is 3 600 MW which is equal to the installed capacity, while the transfer loss is set to 2 %. The optimal capacity for this cable is not determined in this thesis and the capacity is therefore assumed equal with the theoretical maximal output from the wind farm. Since the cable from Dogger Bank to GB-Mid is assumed constructed independent of the cable to Norway, the costs for this cable is not taken into account in the profitability calculation for the cable from Dogger Bank to Norway. Fuel prices in the model are given by Table 8.1.

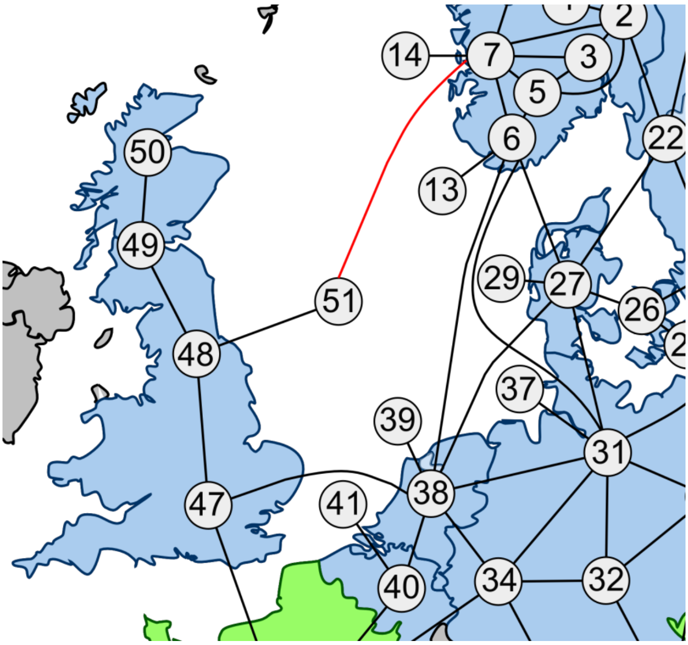

Figure 8.6: HVDC cable from Dogger Bank to Nor-VestSyd (red line)

8.2.1 Generation mix

The generation mix in Great Britain for this scenario is quite similar to the one in Case 4, which is displayed in Figure 8.2. Since the flow from Norway towards Great Britain is limited to the excess capacity on the cable from Dogger Bank to GB-Mid, the average annual flow is slightly reduced. This reduction in imports is mainly compensated by an increase in generation from gas fired plants. An overview of the average annual generated volumes and net export/import for Great Britain is given in Table 8.9.

Table 8.9: Generated volumes by source and net import/export for Great Britain (TWh)

Coal	93.7
Gas	126.1
Renewables	33.0
Nuclear	48.9
Other	1.9
Wind	58.0
Net export to France	0.7
Net import from Norway	6.9
Net import from The Netherlands	2.6
Electricity generated	361.6

8.2.2 Boundary transfer within Great Britain

Transfer across both the GB-ScotN – GB-North and the GB-North – GB-Mid boundaries is quite similar to the findings for the same boundaries in section 8.1.2 and are therefore not discussed further.

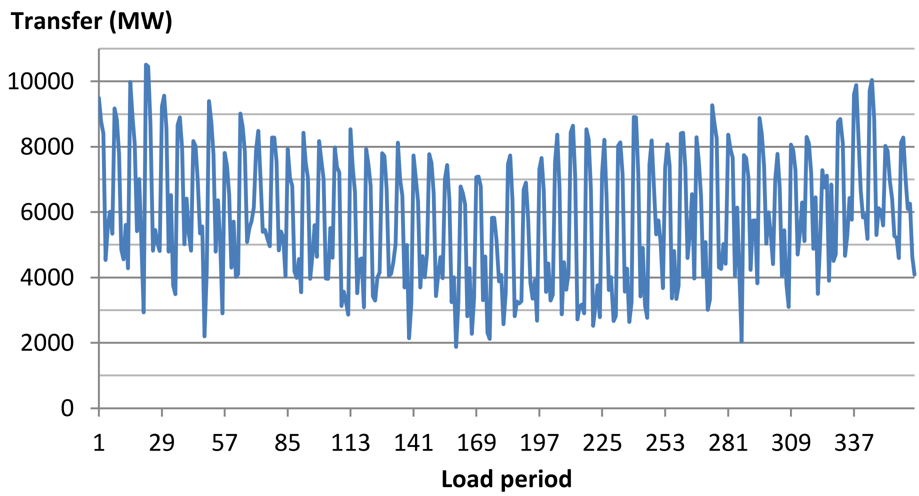

Figure 8.7: Transfer across the GB-Mid - GB-South boundary for each load period throughout a year

For the GB-Mid – GB-South boundary, the transfer is increased compared to Case 4 since the cable to Norway is connected to GB-Mid instead of GB-South.

As a result of this, GB-South is importing the repealed capacity from Norway across the boundary from GB-Mid. An overview of the flow across the boundary for each load period is given in Figure 8.7. Even though the transfer is increased, none of the load periods reaches the maximal transfer capacity across the border, which is 11 500 MW.

8.2.3 Exchange between Southern Norway and Dogger Bank

Transfer from Nor-VestSyd to Dogger Bank is dependent on excess capacity in the cable from Dogger Bank to GB-Mid. This excess capacity is determined by the difference between the cable's capacity and the wind generation in each load period. Transfer across the cable may therefore be affected by the wind generation since the cable's transfer capacity is 'varying' due to the wind generation. Transfer across the cable from Dogger Bank to Nor-VestSyd is given in Figure 8.8.

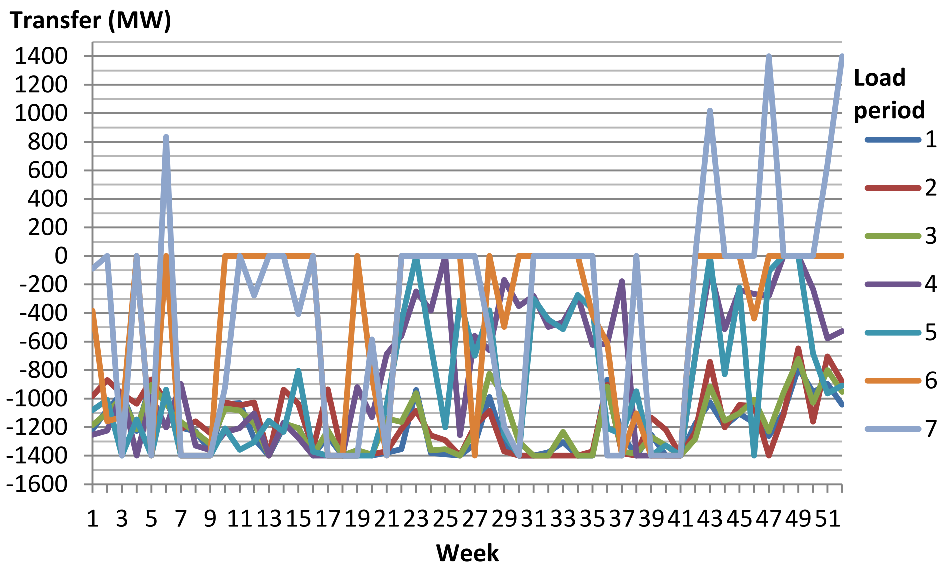

Figure 8.8: Transfer from Dogger Bank to Nor-VestSyd for all load periods throughout a year

A comparison with the finding in Case 4 (Cable from GB-South to Nor-VestSyd) indicates that the annual transferred volume is lower if the cable is connected to Dogger Bank. This is also in accordance with Table 8.10 which show lower annual transferred volumes for a wet, normal and dry year compared to the corresponding values for Case 4, displayed in Table 8.4. Even though the cable in Case 4 is connected to GB-South, comparison with the current cable is reasonable due to the strong boundary between GB-Mid and GB-South and the low losses for transfer across this boundary (0.1 %). The two main reasons for this transfer decrease is the varying transfer capacity across the cable and the increased losses. Marginal cost of wind generation at Dogger Bank is lower than the marginal cost of the capacity transferred from Norway since wind is not storable and transfer losses increases the cost of capacity from Norway. The wind capacity is therefore prioritized in the cable towards Great Britain. According to Figure 8.8, transfer in load periods which had the highest transfer in Case 4, has the largest reduction in transfer in this case. Some of this reduction is due to the constraints on the Dogger Bank – GB-Mid cable.

Table 8.10: Annual transfer from Nor-VestSyd to Dogger Bank for a wet, normal and dry year (TWh)

Transfer from Nor-VestSyd	Wet year	Normal year	Dry year
Export	8.3	8.5	4.0
Import	0.1	0.1	1.2
Net export	8.2	8.4	2.8

An overview of the relative transfer across both cables and relative wind generation at Dogger Bank for all load periods in week 2 and 3 is sketched in

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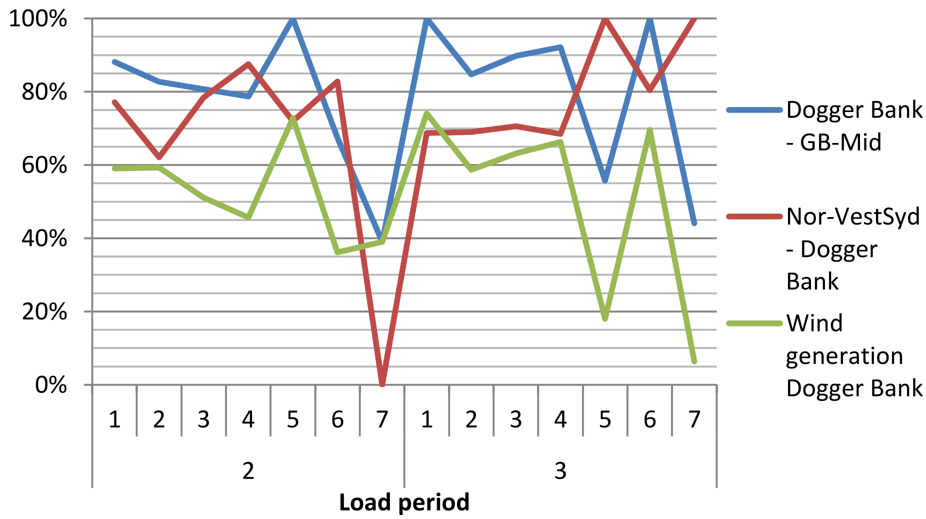

Figure 8.9: Transfer across both cables in week 2 and 3 for a normal year

There is a strong correlation between the transfer from Dogger Bank to GB-Mid (blue line) and the wind generation at Dogger Bank (green line). The transfer from Nor-VestSyd to Dogger Bank on the other hand has a negative correlation with the transfer from Dogger Bank to GB-Mid in periods where this boundary is operated at the limit (100%). Especially in load period 5 week 2 and load period 1 and 6 week 3, the flow from Norway is reduced due to constraints across the Dogger Bank – GB-Mid cable caused by high generation at Dogger Bank.

The second reason is the increased losses across the cables. There is no demand at Dogger Bank and all transfer from Norway is therefore transferred further to GB-Mid. Total losses are therefore 5 %, distributed by 3 % on the cable from Nor-VestSyd to Dogger Bank plus 2 % on the cable from Dogger Bank to GB-Mid. In order to transfer capacity, the price difference across the cables has to exceed 5 %, which is 1 % higher than in Case 4. As a result of these factors, transfer across the cable is reduced with approximately 15 % in a normal year compared to the transfer in Case 4.

8.2.4 Cable cost and congestion rent

The proposed cable from Nor-VestSyd to Dogger Bank is approximately 550 km. Connection point at Dogger Bank, for the cable to Norway, is assumed to be in the middle of the Dogger Bank zone. Cost for the cable is calulated to €990 million based on the €1.8 million/km cost estimate. Total cable cost is estimated to €1 340 million, including €350 million for the converter stations.

The annual congestion rent, costs due to losses and trading result for the cable from Dogger Bank to Nor-VestSyd is given in Table 8.11. The way of calculating congestion rent and costs related to losses are described in section 7.1.4.

Table 8.11: Trading result for a cable from Nor-VestSyd to Dogger Bank

Congestion rent	€40.0 mill
Costs due to transfer losses	€9.8 mill
Trading result	**€30.2 mill**

Due to the cable from Norway, transmission constraints also occur at the cable from Dogger Bank to GB-Mid. Trading result for this cable is given in Table 8.12.

Table 8.12: Trading result for a cable from Dogger Bank to GB-Mid

Congestion rent	€37.0 mill
Costs due to transfer losses	€15.2 mill
Trading result	**€21.8 mill**

The trading result normally devolves the owner of the cable. In this case, the cable from Norway to Dogger Bank creates transfer constraints at the cable from Dogger Bank to GB-Mid. These constraints are reducing the congestion rent for the owner of the cable from Norway. In periods with constraints at the cable from Dogger Bank to GB-Mid, the price at Dogger Bank is mainly determined by the price in Norway plus costs of transfer losses. This is valid as long as energy flows from Norway to Dogger Bank, which is the case for most of the year. The revenue from congestion rent across this cable in these periods is therefore close to zero. Instead the owner of the cable from Dogger Bank to GB-Mid profits from congestion rent. Distribution of the congestion rent between both cable owners is therefore a matter of discussion. For simplicity reasons, the trading result for each cable devolves the owner in its entirety.

Due to the uncertain investment costs for the cable, profitability estimation for several investment costs is given in Table 8.6. The estimate is based on a 6 % discount rate and a repayment period of 40 years, giving an annuity of 0.0665.

Table 8.13: Key figures for a cable with various investment costs

Million €	20 % decrease	Estimated	30 % increase
Investment cost	1072	1340	1742
Net present value	-618	-886	-1288
Trading result	30.2	30.2	30.2
Equivalent present value	71.3	89.1	115.8
Internal rate of return	0.6 %	-	-

The key figures indicate that none of the cost estimates for the cable are profitable based on the trading result alone. Although this cable alternative returns a less negative present value plus a higher internal rate of return than the cable connected to GB-South in Case 4 (Table 8.6). Based on the assumptions taken in the 2020 scenario, a cable via Dogger Bank would therefore be preferable assuming that one of the alternatives were constructed. This is mainly due to less investment costs for a cable from Nor-VestSyd to Dogger Bank since this cable is approximately 300 km shorter than the Norway – GB-South cable. Simultaneously the relative reduction in trading result is less than reduction in investment cost, leaving a higher net present value. If congestion rent for both cables devolved the owner of the Nor-VestSyd – Dogger Bank, the annual profit would be €52 million. Assuming original cost estimate and 40 years repayment, the internal rate of return is 2.3 %. This is less than the 3.5 % risk free rate, indicating that the cable is not profitable based on trading result for both cables either.

8.2.5 The cable's impact on the Norwegian transmission grid

The cable's impact on the Norwegian transmission grid is quite similar to the findings for Case 4, section 8.1.5. Both the transferred volumes and the transfer pattern are relatively equal and the discussion in that section is therefore also valid for this case.

8.3 Case 6: HVDC link from Dogger Bank to Southern Norway

A HVDC cable is connected between Dogger Bank and Nor-VestSyd as illustrated in Figure 8.6 section 0. The transfer capacity is set to 1 400 MW for both directions, while transmission losses in the cable are assumed to be 3 %. Transfer capacity for the cable from Dogger Bank to GB-Mid is 2 200 MW while the transfer loss for this cable is set to 2 %. The sum of the two cables connected to Dogger Bank equals the wind farm's installed capacity. Fuel prices in the model are given by Table 8.1.

8.3.1 Generation mix

The generation mix in Great Britain for this scenario is quite similar to the one in Case 4, which is displayed in Figure 8.2. Since the flow from Norway towards Great Britain is limited to the excess capacity on the cable from Dogger Bank to GB-Mid the average annual flow is considerable reduced. This reduction in imports is mainly compensated by an increase in generation from gas fired plants. An overview of the average annual generated volumes and net export/import in Great Britain, for all the 40 historical years, is given in Table 8.14.

Table 8.14: Average annual generated volumes by source and net import/export for Great Britain (TWh)

Coal	93.9
Gas	128.4
Renewables	33.0
Nuclear	48.9
Other	2.0
Wind	58.0
Net export to France	0.7
Net import from Norway	4.1
Net import from The Netherlands	2.7

8.3.2 Boundary transfer within Great Britain

Transfer across both the GB-ScotN – GB-North and the GB-North – GB-Mid boundaries is quite similar to the findings for the same boundaries in section 8.1.2, while transfer across the GB-Mid – GB-South boundary is similar to the findings for the same boundary in section 8.2.2. None of these boundaries are facing any constraints and they are therefore not discussed any further.

8.3.3 Exchange between Great Britain and Dogger Bank

Transfer between Nor-VestSyd and Dogger Bank is dependent on the generation at Dogger Bank. Average generation at Dogger Bank is 1 228 MW for an entire year resulting in a capacity factor of 34.1 %. Due to the excess capacity in Norway, prices are normally lower in Norway than in Great Britain. Generated capacity at Dogger Bank is therefore mainly transferred towards GB-Mid provided that the cable has excess capacity. In periods where the wind generation at Dogger Bank is less than the capacity towards GB-Mid, additional capacity may be transferred from Nor-VestSyd to utilize the excess capacity (assuming that transfer is profitable). If the generated capacity at Dogger Bank exceeds the transfer capacity towards GB-Mid, the excess capacity is transferred towards Norway. The electricity is transferred to Norway since this 'excess' electricity cannot be transferred elsewhere. Since wind cannot be stored, marginal cost of the wind generation at Dogger Bank plus transfer losses are less than the marginal cost for generation in Norway, assuming that excess energy in Norway can be transferred elsewhere.

An overview of the transfer across both cables and wind generation at Dogger Bank for the load periods in week 2 and 3 is sketched in Figure 8.10.

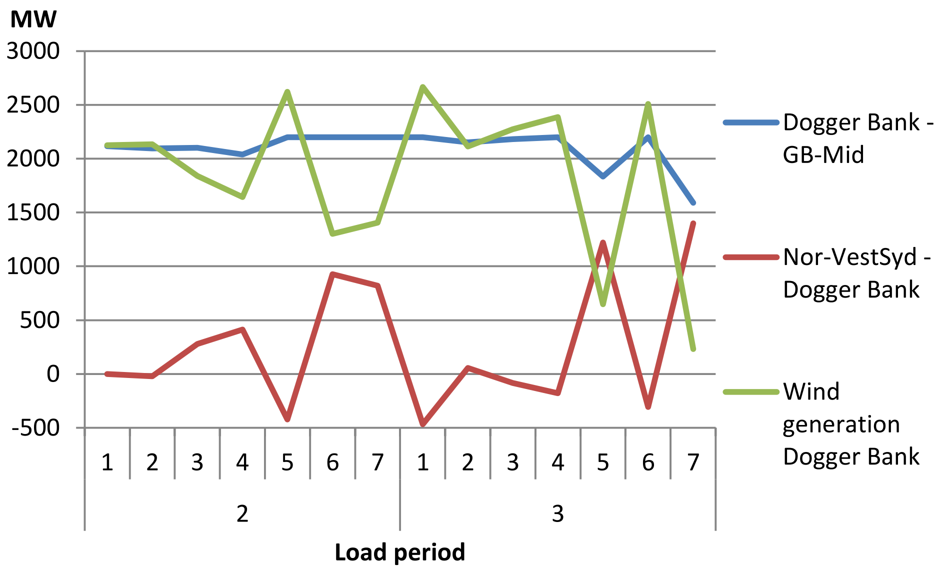

Figure 8.10: Wind generation and transfer via Dogger Bank

The figure indicates that the cable from Dogger Bank to GB-Mid is operated either at the capacity limit or close to this limit in these two weeks. Additionally there are a strong negative correlation between the wind generation at Dogger Bank (green line) and the transfer from Nor-VestSyd to Dogger Bank (red line). In periods where the wind generation exceeds the transfer capacity towards Great Britain, the flow from Nor-VestSyd is negative. For instance load period 5 week 2 and load periods 1, 4 and 6 week 3. Transfer in periods with excess capacity towards Britain is mainly positive for the cable from Norway to Dogger Bank, but this depends on the price difference between Nor-VestSyd and GB-Mid and the cost of transfer losses.

A comparison with the findings in Case 5 indicates that a reduction in transfer capacity from Dogger Bank to GB-Mid reduces the transferred volumes across the cable from Norway. An overview of the transferred volumes across the cable from Nor-VestSyd to Dogger Bank is given in Table 8.15. According to the table, export is decreased due to the magnified constraints. The same factors are simultaneously increasing the import to Norway compared to the imported volumes in Case 5.

Table 8.15: Annual transfer from Nor-VestSyd to Dogger Bank for a wet, normal and dry year (TWh)

Transfer from Nor-VestSyd	Wet year	Normal year	Dry year
Export	6.2	6.2	3.0
Import	1.8	1.8	2.1
Net export	4.4	4.4	0.9

8.3.4 Cable cost and congestion rent

The proposed cable from Nor-VestSyd to Dogger Bank is approximately 550 km. Connection point at Dogger Bank, for the cable to Norway, is assumed to be in the middle of the Dogger Bank zone. Cost for the cable is calculated to €990 million based on the €1.8 million/km cost estimate. Total cable cost is estimated to €1 340 million, including €350 million for the converter stations.

The annual congestion rent, costs due to losses and trading result for the cable from Dogger Bank to Nor-VestSyd is given in Table 8.16. The way of calculating congestion rent and costs related to losses are described in section 7.1.4.

Table 8.16: Trading result for a cable from Nor-VestSyd to Dogger Bank

Congestion rent	€32.9 mill
Costs due to transfer losses	€8.8 mill
Trading result	**€24.1 mill**

Due to the cable from Norway, transmission constraints also occur at the cable from Dogger Bank to GB-Mid. Trading result for this cable is given in Table 8.17.

Table 8.17: Trading result for a cable from Dogger Bank to GB-Mid

Congestion rent	€58.8 mill
Costs due to transfer losses	€12.5 mill
Trading result	**€46.3 mill**

The trading result across the Nor-VestSyd – Dogger Bank cable is lower than the result calculated in Case 5 (Table 8.13 section 8.2.4). Similarly to Case 5, this cable is not profitable either based on the assumptions in the 2020 scenario.

Across the Dogger Bank – GB-Mid cable, the trading result is increased. This is due to the reduced capacity, which magnifies the constraints and increases the congestion rent potential. In Case 5, transfer constraints were normally occurring at the cable from Norway while in Case 6 constraints mainly occur on the connection towards Great Britain. The prices at Dogger Bank are also affected by this shift. Since the cable towards Great Britain mainly had excess capacity in Case 5 while there were frequently constraints at the connection to Norway, prices at Dogger Bank were mainly similar to the prices in Great Britain (adjusted for transfer losses). For Case 6, prices in Norway have a greater influence on the prices at Dogger Bank due to reduced constraints towards Norway and increased towards Britain. This is directly affecting the congestion rent and the trading result across the cable towards Britain is considerable increase in Case 6 compared to Case 5.

The owner of the cable from Norway to Dogger Bank is profiting from a cable with high capacity from Dogger Bank to Great Britain since prices at Dogger Bank then is mainly determined by the prices in Great Britain.

8.3.5 The cable's impact on the Norwegian transmission grid

The number of hours these boundaries are operated at their maximal capacity is displayed in Table 8.18. A comparison with Case 4 (Table 8.8 section 8.1.5) show a reduction of operation at the capacity limits at most of the boundaries. Especially the boundary towards Nor-VestSyd has a considerable reduction. This can be explained by the reduced transfer from this area towards Nor-VestSyd due to less export from Nor-VestSyd to Great Britain. Less export reduces the demand in the area and also the prices and the excess capacity from the Nor-VestSyd area is therefore transferred to areas with higher prices. Due to the reduced transfer, less grid reinforcements are required to resolve the constraints at the boundaries surrounding Nor-VestSyd.

Table 8.18: Number of hours of which the boundary between Nor-VestSyd and other Norwegian areas are operated at maximal transfer capacity

Nor-VestSyd to	Wet year	Normal year	Dry year
Nor-Ostland	998	103	1440
Nor-SorOst	3339	2775	1446
Nor-Telemark	7	0	200
Nor-Sorland	1635	1824	396
Nor-VestMidt	5018	5993	90

9 Sources of error in the model

The EMPS- model is simulating a perfect market. Pricing in the model is quite similar to the method used in Elspot (described in section 2.1.1). Price for the whole traded volume is given by the intersection between the supply and demand curves. This is different from the market in Great Britain where the base load normally is traded separately from the 'shape' load. Pricing in model are therefore more representative for the Nord Pool market than the British. As mentioned previously, the model is simulating a perfect market. Market power or uncertain factors affecting the prices are therefore not allowed for in the model. Uncertain factors could for instance be volatile fuel prices, changes in the legal framework or long-lasting cable and line outages.

Time resolution

A limiting factor, especially for calculating the congestion rent in the model is the aggregation of settlement periods into load periods. This aggregation evens out variations within the load periods. Calculated congestion rent may therefore be reduced and an example of variations within a load period is given in Figure 9.1. The average prices in both areas represent the prices for a load period in the model while the varying prices in both areas represent the actual prices for each settlement period. As indicated in the figure, the congestion rent is less for the average values than for the varying. Congestion rent calculated in the model is therefore most likely less than it would have been in reality. Additionally, time in Great Britain is lagging one hour behind Norway, indicating different peaks since the time difference is not allowed for in the model.

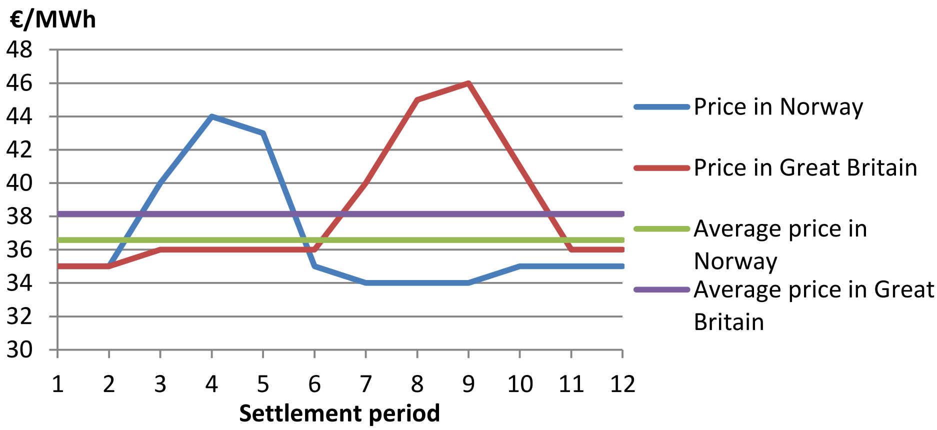

Figure 9.1: Example of prices within a load period

Ramping across the cable

Due to limitations in the power systems, large changes in the output cannot be done momentarily. The restriction for the flow gradient is set to maximum 30 MW/min per connection [51]. Assuming one connection of 1 400 MW, approximately 1.5 hours is needed to change the direction of the flow from maximal export to maximal import. In the model such changes can be done momentarily. An implementation of this ramping delay would most likely reduce the congestion rent.

Fuel prices

There are some uncertainties associated with the fuel prices. Fuel prices in Great Britain is based on actual average prices paid by major power producers in 2010 and are therefore reliable. Fuel prices in the rest of the model are based on these prices in addition to the gas price paid at the German frontier. There are therefore some uncertainties related to the prices in the rest of the model and especially the gas price. As a simplification all countries, except Great Britain have the same gas price even though there in reality are some regional differences. Prices of fuel are affecting the exchange and changes have a relative large influence on the transferred volumes.

Grid representation

The grid representation in the EMPS-model is considerable simplified compared to the real system. Boundaries which have several lines crossing in reality are represented with only one aggregated line in the model. Eventual constraints in more detailed grid representation may therefore not be expressed in the EMPS-model.

Thermal plant's marginal cost and start-up cost

The marginal cost and start-up cost for coal, gas, oil and bio fired plants are estimated values. There are therefore some uncertainties related to the validity of these. Relative small changes may affect the generation mixes and to some extent also the exchange.

10 Conclusion

Three cases for the present power system in Northern Europe have been simulated. Calculations for all three cases indicates that a cable between Norway and Great Britain have a fair-sized arbitrage potential. In both Case 1 and Case 3, annual transferred volume in a normal year is more than 70 % of the theoretical maximum. For Case 2 with equal gas price in the model, the transferred volume was approximately 33 % of the theoretical maximum. However, the congestion rent for none of the three alternatives are sufficient to cover the investment cost of the cables. This is based on a 6 % discount rate and an investment repayment period of 40 years. The cable alternatives Nor-VestSyd - GB-South and Nor-VestSyd – GB-ScotN, Case 1 and Case 3 respectively, returns the same internal rate of return. This indicates that the profitability is equal for both cases. However, due to higher investment cost for Case 1 the net present value for Case 3 is less negative. Assuming that one of the cables was constructed it would be preferable to use GB-ScotN as landing area in Great Britain. This is due to the less negative present value for this alternative. Taken into consideration the reduction in transfer due to equal gas prices in Case 2, eventual reduction in the congestion rent for both Case 1 and Case 3 must be taken into consideration. The simulation in Case 4 also indicate reduced congestion rents towards 2020. Based on the assumptions taken in this report, a cable from Nor-VestSyd to GB-ScotN would therefore be preferable for the cable owner since this alternative is associated with the least economic risk. For the onshore grid in Norway reinforcements is needed regardless of the selected landing area in Great Britain. For the grid in Great Britain grid reinforcements is needed if GB-ScotN is chosen as landing area. Cost of these reinforcements within Great Britain is not quantified, but the fact that reinforcement is needed states that a cable to GB-ScotN triggers upgrade costs within Great Britain.

For the 2020 scenario, three scenarios are simulated. Landing area in Great Britain for Case 4 is GB-South while Case 5 and Case 6 are connected to Dogger Bank. Similarly to the cable alternatives in the 2010 scenario, none of the three proposed cables in the 2020 scenario returns a positive net present value based on the congestion rent. However, the most profitable alternative of these cables is the cable from Nor-VestSyd to Dogger Bank in Case 5. A comparison between Case 5 and Case 6 indicates that a reduction in the transfer capacity from Dogger Bank to GB-Mid reduces both the transferred volume and the arbitrage potential across the cable from Nor-VestSyd to Dogger Bank. In Case 6 the transfer constraints are mainly located across the Dogger Bank – GB-Mid cable. The highest arbitrage potential is therefore between Dogger Bank and GB-Mid. For Case 5, the constraints are mainly at the cable from Nor-VestSyd to Dogger Bank resulting in a higher arbitrage potential across this cable. Assuming that the congestion rent across a cable devolves the owner in its entirety, the owner of the cable from Norway to Dogger Bank would profit from a cable with high capacity from Dogger Bank to Great Britain. A cable with high enough capacity to avoid constraints from Dogger Bank to Great Britain would result in the highest arbitrage potential across the Nor-VestSyd - Dogger Bank cable.

11 Further work

The subject discussed in this report is comprehensive and several important factors affecting the results should be studied further. Some of these factors and more are discussed below. Additionally, the power systems are constantly evolving due to changes in generation capacity, fuel prices, demand, new lines and cables. The generation capacity in Great Britain, for instance, is rapidly changing due to the subsidies for wind generation described in section 0. A frequent update of the model is therefore needed to keep the model as realistic as possible.

Fuel prices and plant marginal cost

Fuel prices for Great Britain is real average prices paid by major power producers in Great Britain. The coal price in the entire model is assumed to be similar to the price in Great Britain. The gas price in northern Europe, except Great Britain, is based on the average price for 2010 at the German frontier plus 5 %. This price is also used in all countries in the model except Great Britain. Both coal and gas prices should therefore be studied in more detail to allow for regional differences.

Marginal cost for thermal power plants is estimated based on the plant's type, fuel, construction year and fuel cost. Similarly, start-up costs for these plants are also based on estimations. A representative sample of the power plants should therefore be compared to their corresponding real plants to verify the estimations or form a basis for adjustments of the estimations.

Plant availability in the entire model is based on data from the European Energy Exchange (EEX). Similar data for Great Britain would make the model more similar to reality.

Optimization of the cable capacity

Several connection sites in Great Britain have been discussed in the report. What have not been discussed are cables with various capacities. Simulations with different capacities should therefore be carried out in order to determine which cable capacity is most profitable. This is especially interesting for the cable from Norway to Dogger Bank where the transfer is depending on the capacity from Dogger Bank to Great Britain.

Socioeconomic surplus

Profitability of all cable alternatives are discussed based on the congestion rent. All alternatives had a negative present value based on the defined assumptions. Even though the present value based on the congestion rent is negative, the present value for the socioeconomic surplus may be positive. Socioeconomic surplus is not calculated for the cable alternatives in lack of a reasonable ceiling price/rationing price to define the consumer surplus. A ceiling price should therefore be defined. Calculations for each cable's profitability based on the change in socioeconomic surplus should thereafter be worked out.

Transfer losses

Transfer losses in the model are based on estimations and educated guesses. Real data should therefore be collected and compared to the losses used in the model.

2020 scenario

The 2020 scenario is based on data from several references. Still, the future is hard to predict and a new evaluation of the assumptions for this scenario would be preferable. This includes installed wind capacity, nuclear capacity, location of new thermal plants and the demand.

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Appendix A Bid types in Elspot

A.1 Hourly bid

In Elspot, hourly bids is the basic type of market order and each participant selects the range of the price steps for these bids individually [6]. The bids have an upper limit of 62 price steps, plus limits for the current ceiling and floor price set by Nord Pool Spot. The simplest bid is a price independent bid for all hours for a specified volume. The participant will then receive, regardless of the price, a schedule of deliverance which coincides with the specified volume. An example of such a bid is displayed in Table A.1. The floor price in Elspot is set to -200€/MWh, as indicated in the table, while the ceiling price is set to 2 000€/MWh. According to the bid, the participant will deliver constantly 60 MW throughout the 24-hour period.

Table A.1: Price independent bid for all hours

Price / Hour	-200	2 000
01-24	60	60

A bid can also be price dependent. If the bid is accepted, a linear interpolation of volumes between each adjacent pair of submitted price steps will be performed by Nord Pool Spot. Such a bid is shown in Table A.2. After the determination of the Elspot price for each hour, a comparison with the participant's daily bid form establishes the traded volumes for the bidder.

Table A.2: Price dependent bid

Price / Hour	-200	30	30.1	40	40.1	45	45.1	2 000
01 02 03	100	100	0	0	-30	-30	-70	-70

According to bid form in the figure, an Elspot price of 25 €/MWh results in a 100 MW purchase for the bidder in the second hour. A price of 30.05 €/MWh results in a 50 MW purchase, while a price of 50 €/MWh results in a sale of 70 MW.

A.2 Block bid

Some participants depend upon accepted bids of the same size for several consecutive hours. This could be the case if the cost of starting and stopping production is high, the production is inflexible or the handling of consumption and contracts are more efficient this way. Nord Pool Spot solves this by allowing block bids. A block bid is an aggregated bid for several consecutive hours, with a fixed price and volume. The participant is free to pick the start and stop hour, but the bid must consist of at least three consecutive hours.

A block bid can only be accepted in its entirety, as an all or nothing condition. The block bid price is compared with the average Elspot prices for the corresponding hours, and the bid is accepted if the following conditions are met[6]:

- If the bid price of a sales block is lower than the average Elspot area price
- If the bid price of a purchase block is higher than the average Elspot area price.

It is also possible to link up to three blocks together, meaning that the evaluation and acceptance of the second block depends on the acceptance of the first block. The third block is dependent on acceptance of both the first and the second block. This way of bidding is useful when the cost of starting a generator depends on whether another generator is already running or not. Linked block bids could also be useful if starting a generator during the night is favourable only if the same generator is planned to run during the day as well. Linked block bids must be either only purchase blocks or sales blocks in the same bidding area.

A.3 Flexible hourly bid

A bid for a not specified single hour, with fixed volume and price, is called a flexible hour bid. This bid is accepted in the hour with the highest price in the calculation, if the price is higher than the limit set by the bid. This bid is useful for companies with power intensive consumption, which would like to shut down production if the spot price exceeds a certain limit and sell the power in the spot market.

Appendix B Previous arrangements in Great Britain

An important part of the restructuring in United Kingdom was the foundation of The England & Wales Electricity Pool. Operationally, the Pool was a mandatory uniform price auction, repeated on a daily basis, into which generators submitted price-quantity bids to provide bulk wholesale supplies of electricity in each half-hour of the next day [52]. According to economic theory, it was predicted that the prices in the Pool would drop quite rapidly after the start-up. The prices were expected to drop to short-run marginal generation costs although this did not happen. Instead the prices rose by 40 % during the first four years. The promised price reduction to the UK households could only be reached by reducing real terms in the operating margins of the transmission system. Throughout the 1990s, both consumer groups representing household users and trade bodies representing industrial users lobbied the UK government and the Office of Gas and Electricity Markets (Ofgem) to call for action to reduce Pool prices. The Department of Trade and Industry were also concerned that these high prices would lead to an excessive increase of new gas-fired Combined Cycle Gas Turbine (CCGT) plants and that this would detriment the deep-mined UK coal industry. In November 1997, Ofgem began a major review of the Electricity Trading Arrangements. This work continued until July 1998 when the final report was released. This report concluded that the Pool would be replaced with a bilateral wholesale market mechanism called the New Electricity Trading Arrangement (NETA). Implementing and testing of NETA took a further 30 months to complete and during this period Pool price began to fall. The 27 March 2001 when NETA started up, prices had already dropped quite a lot. Then after NETA's first year of operation (2001/02) large industrial consumers were paying 15% less in nominal terms, and 61% less in real terms than they paid in 1990/91. In April 2005 NETA was extended to whole Great Britain which now also included Scottish generators and power system. This new arrangement was called British Electricity Trading and Transmission Arrangement (BETTA) [19].

Appendix C The EMPS model

The EFI's Multi-area Power market Simulator model (EMPS) is a computer tool developed by SINTEF Energy Research. It has been in active use in the Norwegian and the Nordic market for more than two decades [15]. The EMPS model is a market simulator which optimizes the utilization of a hydro-thermal power system based on stochastic supply options and demand. Stochastic supply options are for instance inflow to hydro power plants, import and availability of thermal plants. The model provides the user with insight in price formation, energy economics, energy flow, environmental consequences and quality of delivered power [21]. It can also be used to simulate the utilization of local and national energy resources and the interaction between a hydropower system and a surrounding hydro-thermal system. The model is able to simulate decisions and their consequences in the power market with a considerable level of detail. Even if the level of detail is high there are still limitations like behaviour of participants. *"To some extent the focus on the physical system has some limitations, because the behaviour of the participants in a real market is not taken into account, and this may result in deviations between the model and the real market under certain circumstances. This is typically the case in shortage periods, where the market often "overreacts" on the basic physical situation, resulting in much higher prices than the model indicates."* [15] The behaviour of the users make the reality unpredictable, but the simulation will also in extreme situations reflect the trend in the market.

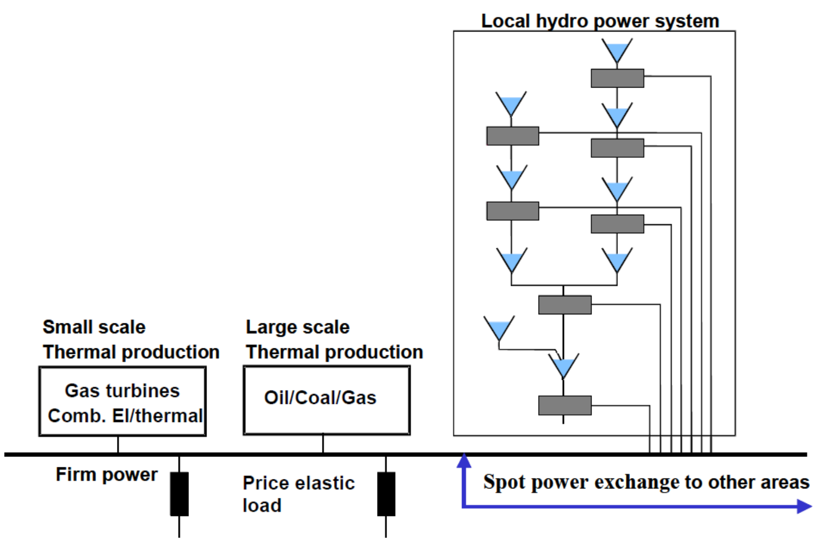

Figure C.1: Aggregated system model [15]

As mentioned previously, the EMPS-model is a multi-area model. Within the different areas, all power plants and consumers are connected to a single bus bar which is shown in Figure C.1.

This means that the model does not take into account potential grid constrains within the area. To get as realistic results as possible, it is important that the grid within the defined area is relatively strong. Considerable bottlenecks in the transmission grid set the boundaries between the areas. The transfer capacity is therefore only defined between the different areas.

Each area has a given demand which varies for each week of the year. The demand also varies a lot through the week, which makes it necessary to divide the week into several accumulated time segments. For instance peak-hour, day, evening, night and weekend. The time steps in the model can either be a week or the number of these accumulated price segments. The model can contain up to 12 different price segments a week. For each of this segment the user can define the number of hours and the output required.

C.1 Degrees of freedom

The EMPS model optimizes the utilization of hydro power within certain degrees of freedom. These are defined as follows for the supply and demand side respectively.

"The degrees of freedom on the supply side are linked to the management of a nature-given and often strongly time-variant hydro power inflow, thermal production and potential import from other areas."

"The degrees of freedom on the demand side are linked to the purchase of power for flexible consumption (electric-boilers, non-guaranteed industrial power), potential export to other interconnected power networks and possible reductions in contract supplies during periods with critically low power supply"[21]

C.2 Water values

Water values are the main tool for operation scheduling for a hydro power producer. Water values are defined as follows:

"In a hydro system with reservoirs, the water value represents the future value of a marginal unit of water in a reservoir. For planning entity, the decision

problem will always be: Should we release water now, or should it be stored for later use. The water value which is normally calculated by means of Stochastic Dynamic Programming (SDP) is the decisive factor for that decision. If the water value is higher than the cheapest competing unit, the water should not be released. In the opposite case, the hydro unit should run." [53]

C.3 The strategy part

The EMPS-model consists of a strategy part and a simulation part. In the strategy part, expected values of stored water in the reservoirs are computed by a function of reservoir volumes and time. This is based on water value method, which make use of stochastic dynamic programming [21]. The water value method requires a simplified model of the hydropower system in order to achieve acceptable computation times. All hydro power production units within each area are therefore aggregated which gives each area one equivalent reservoir and one equivalent power plant. The strategy in the EMPS-model is based on water value calculations for each area decoupled from each other. The mutual coupling between the areas is considered through an iteration process where water values are used as decision basis for simulations of the entire coupled system.

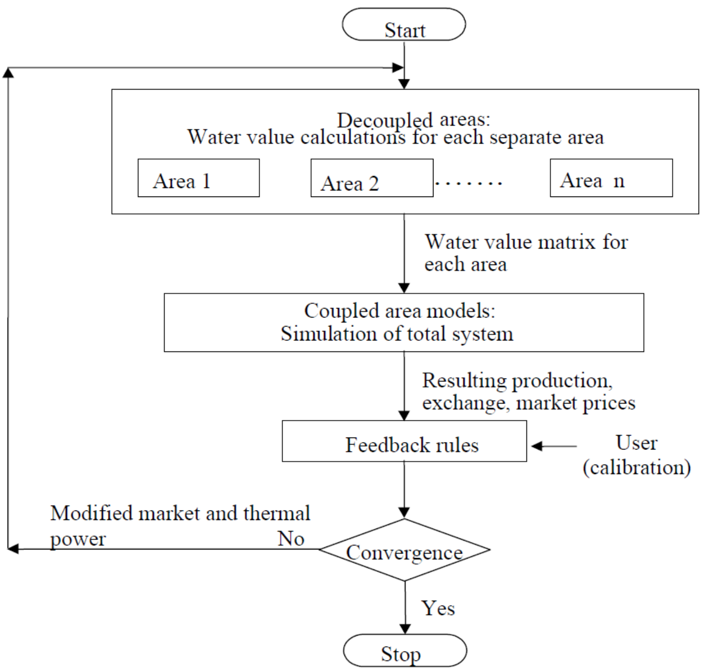

Figure C.2: Water value calculations in the EMPS model [21]

To obtain result as close to reality as possible, the user have do a calibration of the model. This is done by tuning the load (firm power) and occasional power market scaling correction factors, using defined rules [21]. In areas with other production than hydro these must also be taken into consideration. The steps of the water value calculations are shown in Figure C.2.

C.4 The simulation part

When the strategy phase and the water value calculations are done, a system simulation is run to determine how the system operates for the given inflow alternatives [21]. During this simulation, decisions concerning the management of the hydro power in the areas are based on these water values. The decisions are taken on area level and are therefore valid for management of the areas aggregated hydro power model. Production within the given areas is then distributed among available plants for each week or price intervals through an area drawdown model which is linked to each aggregated hydro power model. This detailed drawdown model uses a rule based strategy to distribute the areas hydro production between available plants. The logic of simulation can be summed up in these two steps [15].

"Optimal decisions on the aggregated area level using a network algorithm based on the water values computed in the strategy phase. This is called area optimization. "

"Detailed reservoir drawdown in a ruled based model to distribute the optimal total production from the first step between the available plants. In this step it is verified if the desired production is obtainable within all constraints at the detailed level."

The interaction between area optimization and the reservoir drawdown model is shown in Figure C.3. This figure represents the weekly decision process in the EMPS model, which follow a certain stepwise path. If the calculated result deviates from the optimal decision, more areas are needed or there is a deviation between optimal and calculated production, feedback paths makes it possible to do corrections and run a new simulation.

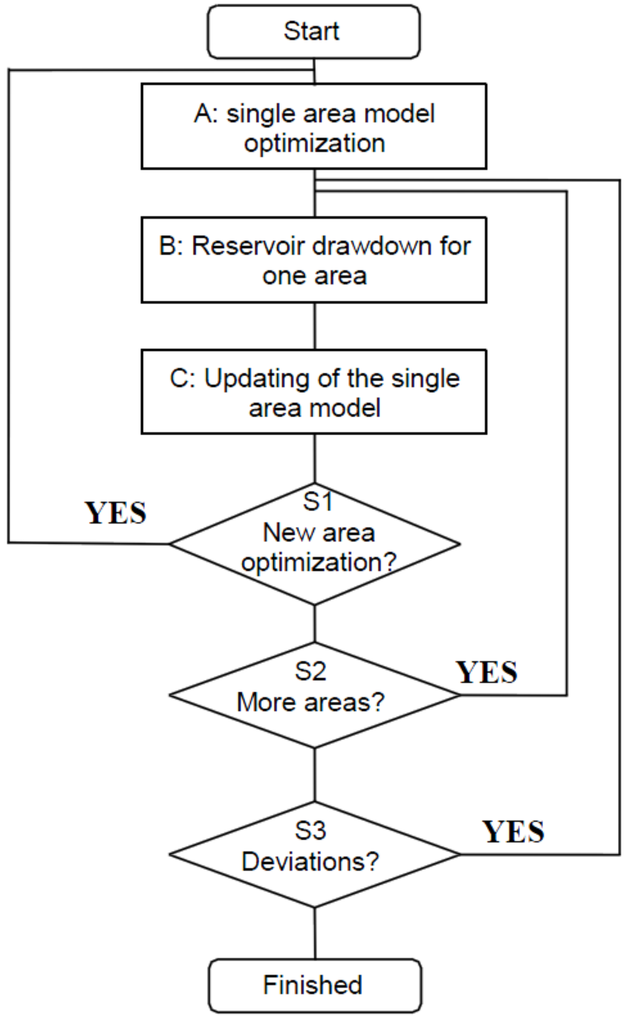

Figure C.3: The weekly decision process in the EMPS model [15]

Appendix D EMPS-areas in the model

Table D.1: Areas in the North European EMPS-model

Area	Area Name	Country
1	NOR-GLOMMA	Norway
2	NOR-OSTLAND	Norway
3	NOR-SOROST	Norway
4	NOR-HALLING	Norway
5	NOR-TELEMARK	Norway
6	NOR-SORLAND	Norway
7	NOR-VESTSYD	Norway
8	NOR-VESTMIDT	Norway
9	NOR-MIDT	Norway
10	NOR-HELGE	Norway
11	NOR-TROMS	Norway
12	NOR-FINNMARK	Norway
13	NOR-S-OWP	Norway
14	NOR-VS-OWP	Norway
15	NOR-V-OWP	Norway
16	NOR-M-OWP	Norway
17	SVER-ON1	Sweden
18	SVER-ON2	Sweden
19	SVER-NN1	Sweden
20	SVER-NN2	Sweden
21	SVER-MOST	Sweden
22	SVER-MVEST	Sweden
23	SVER-SYD	Sweden
24	SVER-S-OWP	Sweden
25	FINLAND	Finland
26	DANM-OST	Denmark
27	DANM-VEST	Denmark
28	DANM-O-OWP	Denmark
29	DANM-V-OWP	Denmark
30	TYSK-OST	Germany
31	TYSK-NORD	Germany
32	TYSK-MIDT	Germany
33	TYSK-SYD	Germany
34	TYSK-VEST	Germany
35	TYSK-SVEST	Germany
36	TYSK-O-OWP	Germany
37	TYSK-V-OWP	Germany
38	NEDERLAND	Netherlands
39	NL-OWP	Netherlands
40	BELGIA	Belgium
41	BE-OWP	Belgium
42	POLEN	Poland
43	TSJEKKIA	Czech Republic
44	OSTERIKKE	Austria
45	SVEITS	Switzerland
46	FRANKRIKE	France
47	GB-SOUTH	Great Britain
48	GB-MID	Great Britain
49	GB-NORTH	Great Britain
50	GB-SCOTN	Great Britain
51	DOGGERBANK	Great Britain

Appendix E Transfer boundaries in Great Britain

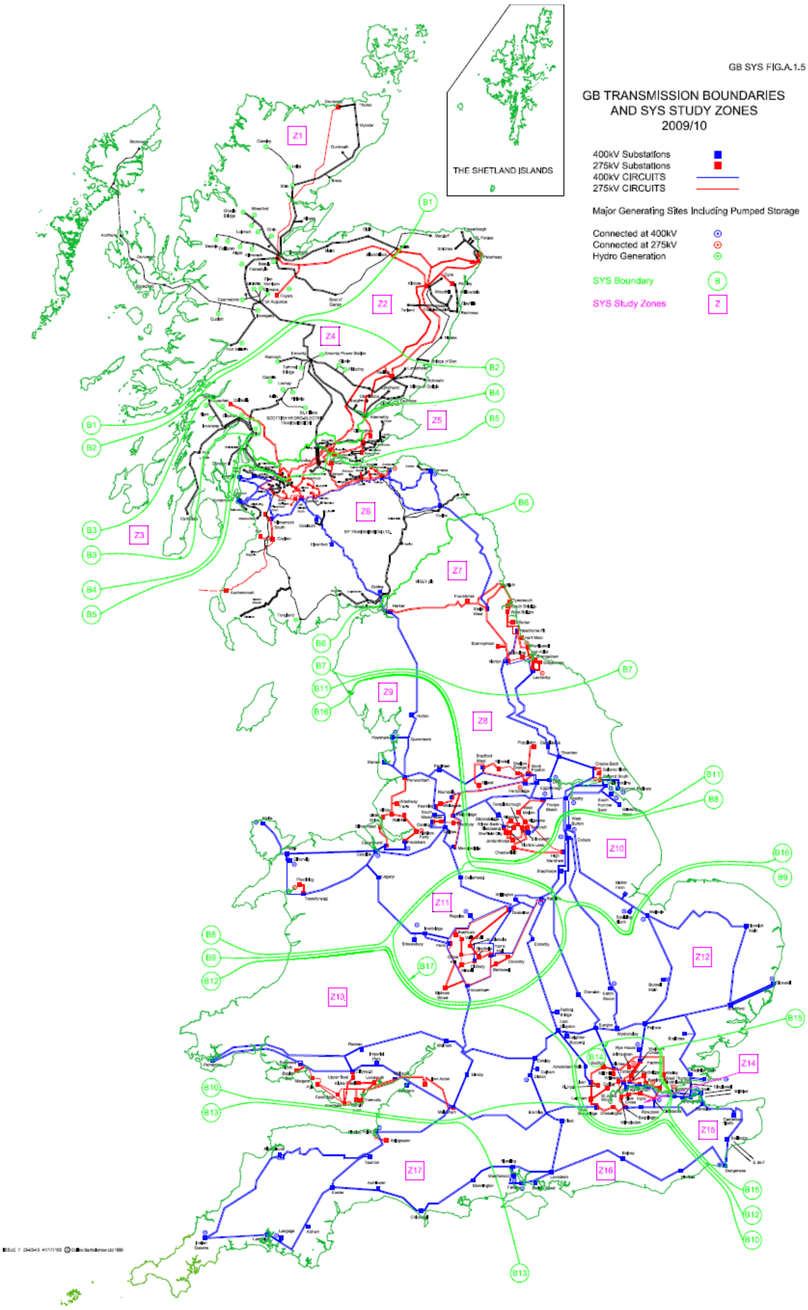

Figure E.1: Transfer boundaries in Great Britain [18]

Appendix F Nuclear generation

Table F.1: Historical volumes for nuclear generation in Great Britain

				Production (TWh)						
Station	**Plant Owner**	**Area**	**Capacity (MW)**	**2009/10**	**2008/09**	**2007/08**	**2006/07**	**2005/06**	**Average**	**Scaled**
Hunterston	British Energy	GB-North	1074	5.93	5.21	4	3.5	7.91	5.31	5.76
Torness	British Energy	GB-North	1215	9.01	9.55	8	7.6	9.4	8.71	9.45
Hartlepool	British Energy	GB-Mid	1207	6.83	1.28	4.6	5.6	5.21	4.70	5.10
Wylfa	NDA	GB-Mid	980	5.4	5.85	4.93	5.7	6.5	5.68	6.15
Heysham	British Energy	GB-Mid	2406	14.95	9.08	12.3	16.9	15.79	13.80	14.97
Dungeness B	British Energy	GB-South	1081	3.96	2.94	6.4	4.5	5.48	4.66	5.05
Hinkley Point B	British Energy	GB-South	1261	4.87	5.19	5.3	4.2	7.69	5.45	5.91
Sizewell B	British Energy	GB-South	1200	8.95	9.65	9.8	8.9	8.9	9.24	10.02
Oldbury	NDA	GB-South	470.4	2.7	1.5	1.05	0.69	1.45	1.48	1.60
Sum			10894.4	62.6	50.25	56.38	57.59	68.33	59.03	64.00

The sum of average actual production for these five years is less than the assumed production in the model. In order to allocate this additional generation, every plant's average production are multiplied with a scaling factor. This factor is determined by dividing the assumed annual production in the model by the calculated average value: $\frac{64}{59.03} = 1.084$

Annual generation data for plants owned by British Energy are fetched from [54], while data from plants owned by National Decommission Authority (NDA) is fetched from [55], [56], [57], [58] and [59].

Appendix G Demand allocation

Table G.1: Calculated allocation of demand for each county

Area	Consumer sales	Pumped storage	Losses	Unallocated
Scotland North	5 277	529	734	698
Scotland South	21 734	777	2 016	2 873
North West	32 442		2 980	4 289
West Midlands	24 624		2 262	3 255
Yorkshire and the Humber	24 372		2 238	3 222
East Midlands	21 185		1 946	2 801
North East	12 034		1 105	1 591
Wales North	3 795	3537	349	502
Wales South	11 925		1 095	1 577
East of England	26 956		2 476	3 564
Greater London	41 081		3 773	5 431
South East	39 747		3 651	5 255
South West	24 904		2 287	3 292
Sum	290 075	4 843	26 912	38 349

The sum of both consumer sales, pumped storage and losses are given by [27], while 'unallocated' is the remaining demand except for energy used for electricity generation and electricity used by petroleum refineries. The pumped storage generation is evenly allocated based on the respective area's installed capacity. Losses are distributed evenly with regards to consumer sales, based on the assumption that losses in GB-ScotN are 1.5 times higher per consumed unit than the rest of Great Britain. This assumption is based on the low density of people and the large share of wind and hydro generation in remote areas. Unallocated consumption is distributed evenly with regard to consumer sales in each area. This category includes unallocated sales, sales directly from high voltage lines, electricity used by energy industry and more. It is therefore assumed that these factors are proportional to consumer sales in each area. As mentioned above electricity used for generation and electricity used by petroleum refineries is not included. These are just calculated for each EMPS-area. Electricity used for generation is calculated based on the area's fixed nuclear production and their installed capacity of coal, gas and oil fired power plants. In 2009, 16 474 GWh was consumed by the producers themselves for electricity generation [27]. Each area's share is given in Table G.2.

Table G.2: Electricity used for generation

Area	Annual nuclear generation (GWh)	Thermal prod. ex. Nuclear (GWh)	Nuclear and other thermal (GWh)	% share of electricity used for generation	Electricity used for generation (GWh)
GB-ScotN	0	10334	10334	2.94 %	484
GB-North	15200	16282	31482	8.94 %	1473
GB-Mid	26200	145889	172089	48.89 %	8054
GB-South	22600	115495	138095	39.23 %	6463
Total	64000	288000	352000	100.00 %	16474

Electricity used by petroleum refineries are allocated based on the location of the eleven refineries in Great Britain. It is assumed that the consumption is equal at all sites, resulting in the distribution given in Table G.3 for a given demand of 4 347 GWh in 2009 [27].

Table G.3: Electricity used by petroleum refineries

Area	Number of refineries	Energy used by refineries (GWh)
GB-ScotN	0	0
GB-North	2	790
GB-Mid	5	1976
GB-South	4	1581
Total	11	4347

By summing up, the demand for each EMPS-area can be calculated. Annual area demand and each area's share of total demand are given in Table G.4.

Table G.4: Annual demand for the Great Britain areas

Area	Annual demand (GWh)	Share of total demand
GB-ScotN	7 721.6	2.03 %
GB-North	29 664.5	7.79 %
GB-Mid	158 556.9	41.62 %
GB-South	185 057.0	48.57 %
Sum	381 000.0	100.00 %

Appendix H Transfer from GB-North – GB-Mid in Case 1

Table H.1: Transfer across the GB-North – GB-Mid boundary, given in MW, with a link from GB-South to Nor-VestSyd. (LP = load period)

Week	LP 1	LP 2	LP 3	LP 4	LP 5	LP 6	LP 7
1	2 546	2 673	2 150	873	1 545	776	694
2	2 454	2 591	2 026	1 137	1 182	810	800
3	2 702	2 742	2 123	1 222	1 317	849	750
4	2 640	2 740	2 118	1 146	1 679	851	779
5	2 663	2 760	2 384	1 202	2 159	1 252	781
6	2 596	2 720	2 140	1 200	1 586	917	711
7	2 498	2 633	2 221	1 441	1 119	752	1 004
8	2 606	2 616	2 369	1 232	1 229	921	1 021
9	2 591	2 706	2 343	1 541	1 236	882	991
10	2 620	2 691	2 380	1 474	1 269	927	1 050
11	2 573	2 423	2 398	1 003	1 453	1 110	1 163
12	2 615	2 462	2 398	1 046	1 422	1 099	1 111
13	2 558	2 436	2 353	1 096	1 319	967	1 010
14	2 241	2 201	1 145	617	1 317	962	1 058
15	2 226	2 171	1 106	577	1 268	999	1 040
16	1 998	1 970	1 523	540	1 182	708	874
17	1 924	1 866	1 753	643	1 166	723	834
18	1 845	1 855	1 339	436	1 043	784	889
19	1 882	1 845	1 754	480	561	945	928
20	1 261	1 341	1 146	476	374	922	1 084
21	845	854	151	823	538	1 127	1 198
22	976	958	698	673	554	1 143	1 209
23	1 086	1 045	956	677	492	1 095	1 166
24	1 006	992	706	692	592	1 092	1 293
25	1 093	998	920	557	426	940	1 102
26	1 075	1 006	957	508	345	909	1 065
27	994	984	519	585	477	997	1 151
28	918	897	499	548	408	986	1 071
29	787	802	169	445	258	841	903
30	525	565	-63	508	371	914	957
31	376	448	-50	498	391	993	994
32	473	502	11	607	477	1 070	1 064
33	401	445	85	681	585	1 085	1 183
34	538	574	135	594	456	1 031	1 139

35	575	595	192	434	437	984	1 026
36	1 161	1 081	959	297	313	751	991
37	1 321	1 248	1 123	428	303	819	961
38	1 305	1 256	1 103	513	455	872	1 128
39	1 295	1 269	979	619	605	1 233	1 286
40	1 516	1 465	1 404	496	307	1 038	1 005
41	1 597	1 466	1 392	385	94	737	846
42	1 514	1 421	1 398	432	242	868	1 028
43	1 483	1 434	1 198	499	333	1 042	1 137
44	1 463	1 361	1 380	275	67	786	881
45	1 436	1 336	1 297	270	50	817	883
46	1 360	1 352	684	628	438	1 128	1 270
47	1 528	1 449	1 345	535	291	1 101	1 208
48	1 791	1 890	1 447	358	217	886	1 153
49	1 765	1 935	1 437	455	70	779	1 017
50	1 734	1 869	1 244	231	70	569	818
51	1 380	1 318	1 385	611	432	1 139	1 241
52	1 879	1 839	1 644	738	888	1 320	1 505

Appendix I Transfer from GB-South to Nor-VestSyd in Case 1

Table I.1: Transfer for all load periods in a normal year from GB-South to Nor-VestSyd (MW)

Week	LP 1	LP 2	LP 3	LP 4	LP 5	LP 6	LP 7
1	-1 400	-1 400	-1 400	1 400	1 314	1 400	1 400
2	-1 400	-1 400	-1 199	1 400	1 400	1 400	1 400
3	-1 400	-1 258	-966	1 400	1 400	1 400	1 400
4	-1 400	-1 400	-1 216	1 400	1 400	1 400	1 400
5	-1 400	-1 400	-1 400	1 400	1 093	1 400	1 400
6	-1 400	-1 400	-1 371	1 400	1 400	1 400	1 400
7	-1 231	-696	-864	1 400	1 400	1 400	1 400
8	-68	0	97	1 400	1 400	1 400	1 400
9	-1 280	-1 014	-1 068	1 400	1 400	1 400	1 400
10	-283	-93	-63	1 400	1 400	1 400	1 400
11	5	0	597	1 400	1 400	1 400	1 400
12	-51	0	771	1 400	1 400	1 400	1 400
13	53	0	168	1 400	1 400	1 400	1 400
14	30	0	1 400	1 400	1 400	1 400	1 400
15	0	0	1 400	1 400	1 400	1 400	1 400
16	0	0	1 400	1 400	1 400	1 400	1 400
17	0	0	1 400	1 400	1 400	1 400	1 400
18	-160	-412	371	1 400	1 400	1 400	1 400
19	-699	-925	1 188	1 400	1 400	1 400	1 400
20	-577	-984	966	1 400	1 400	1 400	1 400
21	193	-153	1 400	1 400	1 400	1 400	1 400
22	189	0	1 400	1 400	1 400	1 400	1 400
23	19	0	1 322	1 400	1 400	1 400	1 400
24	0	0	1 400	1 400	1 400	1 400	1 400
25	-835	-560	963	1 400	1 400	1 400	1 400
26	0	0	129	1 400	1 400	1 400	1 400
27	202	49	1 400	1 400	1 400	1 400	1 400
28	223	89	1 400	1 400	1 400	1 400	1 400
29	52	0	1 400	1 400	1 400	593	643
30	0	-207	1 400	1 282	1 400	1 387	46
31	87	-359	1 400	1 279	1 400	1 400	688
32	223	-266	1 400	1 400	1 400	1 400	1 400
33	-464	-949	1 371	1 400	1 400	1 400	1 400

34	-152	-762	1 400	1 400	1 400	1 400	1 400
35	-1 026	-1 363	1 218	1 400	1 400	1 400	1 400
36	-1 342	-1 400	0	1 400	1 400	1 400	1 400
37	-1 400	-1 400	-27	1 400	1 400	1 400	1 400
38	-1 013	-1 379	0	1 383	536	1 400	0
39	-1 243	-1 400	0	317	835	664	0
40	-1 219	-1 362	80	1 400	1 400	1 361	882
41	-79	0	-9	1 400	1 400	1 400	1 400
42	-42	0	129	1 400	1 400	1 400	1 400
43	0	0	1 370	1 400	1 400	1 400	1 400
44	-16	0	740	1 400	1 400	1 400	1 400
45	-72	0	915	1 400	1 400	1 400	1 400
46	26	0	1 400	1 400	1 400	1 400	1 400
47	0	0	1 051	1 400	1 400	1 400	1 400
48	-500	-246	598	1 400	1 400	1 400	1 400
49	-693	-157	493	1 400	1 400	1 400	1 400
50	-1 400	-1 261	-900	1 400	1 400	1 400	1 400
51	-390	-474	1 177	1 365	1 400	1 400	1 400
52	38	0	1 400	1 400	1 400	1 400	1 400

Appendix J Capacity flow in Great Britain 2010/2011

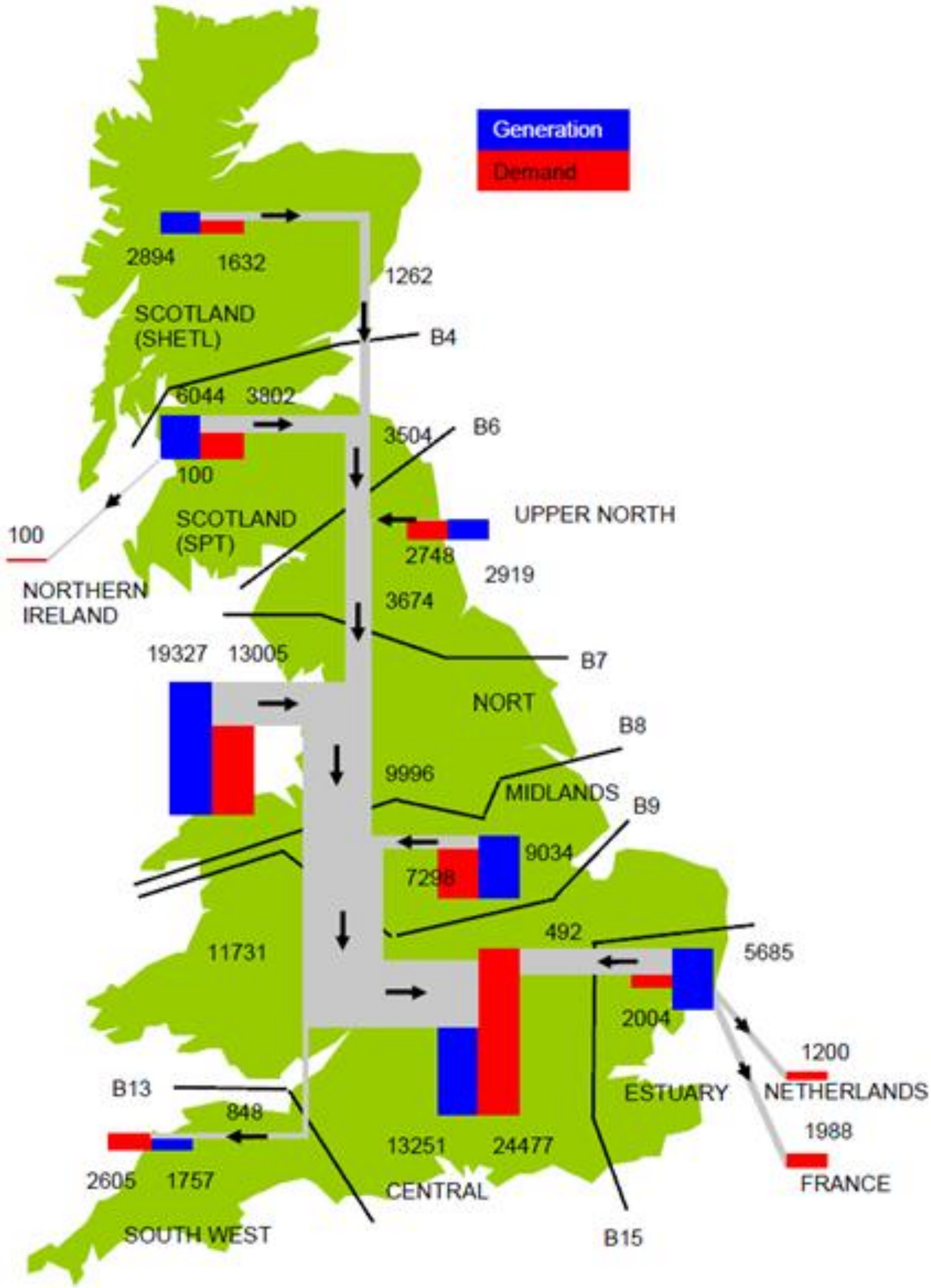

Figure J.1: Assumed winter peak capacity flow in Great Britain 2010/11 [18]

Appendix K Transfer from GB-South to Nor-VestSyd in Case 2

Table K.1: Transfer from GB-South to Nor-VestSyd in a normal year, Case 2 (MW)

Week	LP1	LP 2	LP 3	LP 4	LP 5	LP 6	LP 7
1	-1 400	-1 400	-1 400	0	0	1 400	1 400
2	-1 400	-1 400	-1 392	0	0	1 400	1 400
3	-1 400	-1 400	-1 396	-88	0	1 400	1 400
4	-1 400	-1 400	-1 381	0	0	1 400	1 400
5	-1 400	-1 400	-1 400	-15	0	1 400	1 400
6	-1 400	-1 400	-1 384	0	0	1 400	1 400
7	-1 305	-997	-1 065	320	0	1 400	1 400
8	-564	-34	-26	1 250	0	1 400	1 400
9	-1 400	-1 200	-1 077	227	0	1 400	1 400
10	-806	-153	-81	1 133	0	1 400	1 400
11	-194	0	0	1 400	60	1 400	1 400
12	-311	-42	0	1 400	1 400	1 400	1 400
13	-72	0	-3	1 400	591	1 400	1 400
14	-2	-3	0	1 253	917	1 120	1 087
15	-38	0	0	1 400	827	1 400	1 400
16	-121	0	-49	1 350	263	1 400	1 400
17	-72	0	-43	1 318	0	1 400	1 249
18	-17	0	-55	168	0	1 400	844
19	-404	-35	-412	425	0	1 400	1 400
20	-191	0	-221	521	0	1 400	1 400
21	0	0	0	587	605	798	111
22	-29	0	-110	905	0	1 400	1 369
23	-24	0	329	672	1 400	1 400	1 400
24	0	0	234	1 067	1 400	1 400	1 400
25	-4	0	-51	357	0	1 400	1 200
26	-373	0	-360	0	0	1 400	1 400
27	-5	0	-11	1 152	0	1 400	465
28	0	0	-5	92	0	1 203	0
29	0	0	-7	0	175	0	-763
30	-16	0	-94	-321	148	-13	-1 131
31	0	0	0	-74	0	0	0
32	0	0	0	342	363	958	611
33	-107	0	-80	1 165	509	529	351

34	0	0	0	1 400	0	1 400	1 400
35	-113	0	-220	1 372	184	1 400	1 400
36	-260	0	-227	126	0	802	325
37	-616	-172	-665	0	0	1 400	232
38	-1 400	-1 400	-959	0	0	0	0
39	-1 384	-1 038	-1 054	-380	0	-346	-23
40	-412	0	-335	0	0	209	0
41	-674	-121	-452	0	0	725	1 400
42	-508	-166	-392	110	0	1 400	1 400
43	-42	0	-2	1 095	263	1 400	1 400
44	-237	0	-70	91	1 263	1 400	1 400
45	-298	-76	-126	1 400	1 400	1 400	1 400
46	-83	0	-7	1 400	45	1 400	1 400
47	-635	-52	-72	1 137	1 400	1 400	1 400
48	-521	-713	-404	1 200	700	1 400	1 400
49	-1 400	-1 027	-534	1 213	840	1 400	1 400
50	-1 400	-1 400	-1 167	0	0	1 400	1 400
51	0	0	0	1 400	0	1 400	1 400
52	0	-13	0	1 400	10	1 400	1 400