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Investment Analysis with the EMPS Model with Emphasis on Transmission Capacity Increase to other Power Systems

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Problem Description

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The EMPS model is a fundamental model for optimizing and simulation of large power systems with a substantial amount of hydro power. It is developed by SINTEF Energy Research and is commonly used among participants in the Nordic power market. SINTEF Energy Research has recently developed investment functionality which makes it possible to optimize implementation of certain capacity in production or transmission

The task
The purpose of this thesis is bisected:

1. Study and learn how to use the EMPS model
2. Study the newly developed investment model
3. The investment model uses average prices. Especially for analysis of exchange with continental Europe it is necessary to divide the week in several periods (peak, high day etc). Implement this feature.
4. Implement a maximum capacity on investments.
5. Exchange price-volume relations for exchange with Germany and the Netherlands
6. Do an investment analysis with the investment model to find optimal investments in transmission capacity between Norway and the Netherlands.
7. Do sensitivity analyses for important assumptions (price dependant contracts used to model Germany, Netherlands),
8. Document and discuss the analysis as well as the functionality of the investment model

Point 1-4 are done together with Steinar Beurling

Assignment given: 22. January 2010
Supervisor: Gerard Doorman, ELKRAFT

Abstract

The EMPS model is a fundatmental model for optimizing and simulation of power systems with substantial amounts of hydro power, developed by SINTEF Energy Research. Recently SINTEF Energy Research developed investment functionality making it possible to run optimal investment analysis of thermal power, wind power and transmission capacities.

The purpose of this thesis is to study and learn how to use both the EMPS and the newly developed investment model. The investment model is to be improved to use price segments instead of weekly average prices when calculating the profits and to implement the option to set a maximum capacity. Furthermore simplistic models of Germany and the Netherlands are to be constructed to be able to use the investment model to find the optimal transmission capacity between Norway and the Netherlands.

The investment analysis resulted in an investment of 6000 MW in transmission capacity between Norway and the Netherlands. 6000 MW was the limit due to limitations in the grid from "Sørlandet" to the other parts of Norway. However the way the Netherlands are modelled do not take into account that the prices in the Netherlands also would change as a function of this capacity increase so it is fair to say that the invested capacity is too large. The investment analysis does show that an investment should be made as it is very profitable. For instance would an investment in the region of 1200 MW result in the full investment costs beeing payed back within 3 years of installation according to the investment analysis.

The investment functionality is a program that is quick and easy to use. It provides the user a way to specify a lot of different investment alternatives. The program can be used to see the optimal investment in one or more investment alternatives and it also shows the impact they possibly have on each other. The program saves the user a lot of time as the user no longer has to manually add the investments into the EMPS model. There are however still a few errors that have to be fixed in the program and new features that could be added to improve the results, such as non-linear investment costs.

Preface

This master thesis is done at the Department of Electric Power Engineering at NTNU, spring 2010.

I would like to thank my supervisor prof. Gerard Doorman at NTNU. I would also like thank Stefan Jaehnert for helping me get started with the EMPS model and for providing me with the Nordic model. Ove Wolfgang was of great help when having problems with the investment analysis. Finally I would like to thank Steinar Beurling for his collaboration on parts of this thesis.

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Chapter 1

Introduction

The EMPS model is a fundamental model for optimizing and simulation of power systems with substantial amounts of hydro power, developed by SINTEF Energy Research. Recently SINTEF Energy Research developed investment functionality making it possible to run optimal investment analysis of thermal power, wind power and transmission capacities.

The purpose of this thesis is to examine and improve the investment functionality by using it to investigate the profitability of investing in additional transmission capacity to the Netherlands.

In chapter 2 and 3 brief introductions to the EMPS model and the investment functionality will be given.

In Chapter 4 improvements to the program will be made. The improvements will be to add the possibility to set a maximum capacity for the investment alternatives and to change the profit calculation so they take into account all the price segments used in the EMPS model instead of just using the weekly prices. Chapter 2, 3 and 4 are done in collaboration with Steinar Beurling.

To be able to run investment analysis on the profitability of increasing the capacity to other power systems like Germany and the Netherlands a way to model these areas is needed. In Chapter 4 a simplistic model using price dependant contracts to model the import and export in these areas will be constructed.

In the final part of the thesis simulations using the investment analysis will be carried out to study the profitability of investing in additional capacity to the Netherlands. The impact varying prices in the Netherlands and the impact increased wind capacity has on the investments to the Netherlands will also be studied.

Chapter 2

EMPS

Production scheduling for power systems where large parts consists of hydro power is a complex task. These systems are characterized by large differences in supply due to changing hydrological conditions, both within a year and between years.

To analyze these power systems, a power market simulator that can handle the complexity is needed. The EMPS model is one such simulator that aims at optimal use of hydro resources, in relation to uncertain future inflows, thermal generation, power demand and spot type transactions within or between areas. The model consists of two main parts, one strategy part and one simulation part. [10]

In the strategy part, regional decision tables in the form of water values are computed for each area in the system, using stochastic dynamic programming. [10] In the simulation part optimal decisions are evaluated based on historic hydrological data, typically 30-100 years. Power production is determined for each time step in a market clearing process, based on the computed water values for each area. This will be further discussed in chapters 2.2 and 2.3.

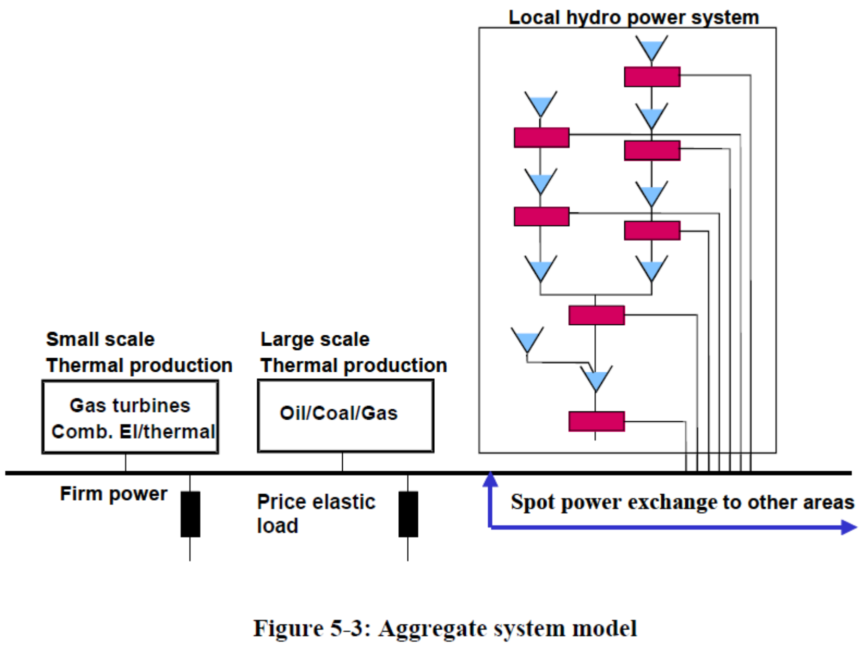


Figure 2.1: Aggregate System model[5]

2.1 Physical modeling

The power system is modeled by dividing it into multiple areas. Each area can contain power production modeled as either hydro or thermal power, in addition to demand contracts. Each area will also have electrical connections with the surrounding areas. A schematic diagram of an area is shown in figure 2.1. An area could, but does not have to, include all elements.

2.1.1 Hydro power

Hydro power is modeled by a series of hydro power modules, with either regulated or unregulated inflow, or a combination of both. The unregulated inflow is the inflow that cannot be stored in the module's reservoir. The EMPS model uses a standard module to describe each hydro module. The module consists of a reservoir, a generator and information about inflow and restrictions. Different endpoints may be defined for spillage, bypass and

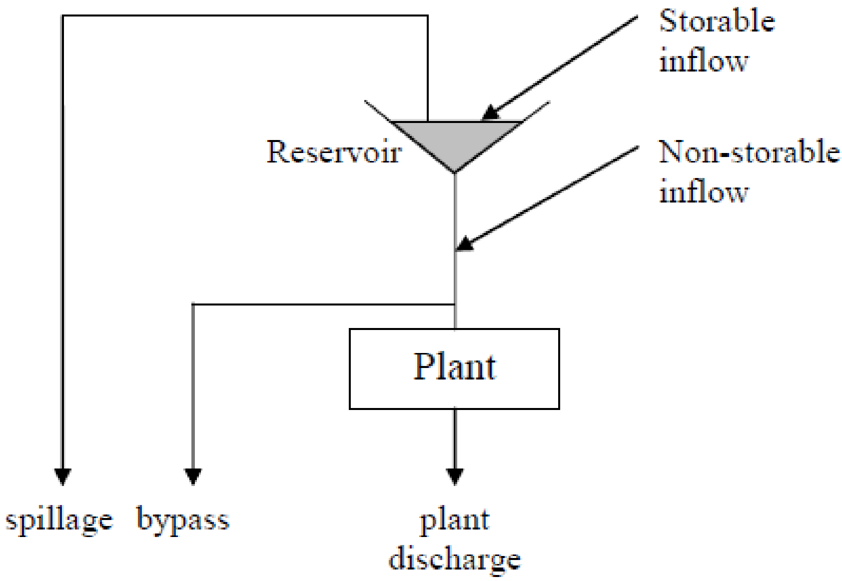


Figure 2.2: Hydro power module[5]

discharge. E.g. can bypass and discharge continue down the same river system, while spillage may be lost. Figure 2.2 shows a schematic diagram of a standard hydro power module. [5] As figure 2.1 indicates, the local hydro system could consist of several hydro modules that can be both series and parallel coupled. A single river can have multiple hydro modules, and several rivers can congregate into one river, causing one module to possibly have multiple reservoirs.

Reservoir

The most important parameter for the reservoir is its volume, which is given in Mm^3 and must always be specified. A completely unregulated reservoir would be modeled with a reservoir volume of 0. Since the power output increases with the water column above the generator, a piecewise linear curve describing the relation between the volume and the corresponding reservoir level can be specified. This results in a more realistic model where production will depend on the reservoir level.

Plant

The minimum specifications that are needed for the plant are the discharge capacity in $\frac{m^3}{s}$ and its average energy equivalent in $\frac{kWh}{m^3}$. The energy equivalent states how much energy is stored in the reservoir per m^3 of water in the reservoir, and is calculated as in (2.1). [5]

$$e = \frac{1}{3.6 \cdot 10^6} \cdot \gamma \cdot g \cdot H \cdot \eta \tag{2.1}$$

where

γ	-	Water density $\left[\frac{kg}{m^3}\right]$
g	-	Gravity acceleration $\left[\frac{m}{s^2}\right]$
H	-	Plant Head $[m]$
η	-	Plant efficiency

Constraints

Multiple constraints could be attributed to each module. It may have one or more of the following constraints: [5]

- Maximum and minimum reservoir level
- Maximum and minimum discharge
- Maximum and minimum bypass

The constraints can be hard, i.e. satisfied at any cost, or soft which means that they are satisfied as long as production is not lost. Failure to satisfy the soft constraints is penalized by a given penalty function.

Pumping

In some modules, pumping is used to pump water between reservoirs in order to increase the potential energy of the water. This is done at times with low prices, typically during night in systems with much thermal power. In systems with much hydro power, this is often used to improve the total utilization of the water. [5]

2.1.2 Thermal power

A thermal power plant is usually modeled as price dependent supply. It is represented by its expected capacity and the associated production costs, which is mainly fuel costs. Capacity is given in MW, production costs in $\frac{cent}{kWh}$ and expected availability in %. E.g. a 100 MW plant with 80% availability will be treated as an 80MW plant in the simulations. This model assumes that fuel can be bought whenever needed, which is a valid assumption for coal, oil and nuclear powered plants and for some types of gas power plants. Gas power can also be modeled with fixed supply, local gas storage or with specified gas tapping within periods. [5]

2.1.3 Wind power

Wind power in EMPS is in this report modeled as a hydro unit. Inflow is created from wind patterns and used as unregulated inflow, thus eliminating the need for a reservoir. Wind power could also be modeled as a contract with a sale price of zero.

2.1.4 Demand

Demand can be modeled as either **firm demand** or **price elastic demand**. Traditionally, the firm demand, which include industrial, service and domestic sectors, has been considered completely inelastic. But after deregulation of power markets it has become clear that even firm demand has some price elasticity. [5]

Firm demand

An example of an annual firm demand profile can be seen in figure 2.3. Firm demand is defined by: [5]

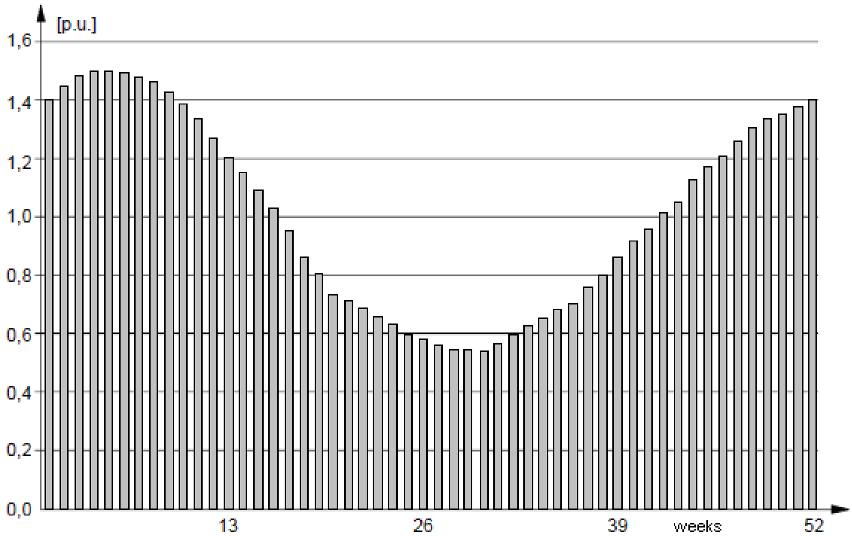


Figure 2.3: Example of an annual demand profile[5]

- An annual quantity in GWh
- An annual profile with a time step of one week
- A distribution between load periods within the week

Demand for a single week is given in (2.2), where f_i is the relative demand factor for week i.

$$W_i = \frac{f_i}{\sum_{i=1}^{52} f_i} \cdot W_{year} \tag{2.2}$$

Demand within the week is described by a number of factors relative to each other, dividing weekly demand between peak hours, weekend, night, etc. This way, EMPS operates with time periods shorter than the basic time step of one week.

Price elastic demand

The price elastic demand is defined by: [5]

- A weekly quantity in GWh
- A switch-off price in $\frac{cent}{kWh}$

The intention of is that a price elastic demand will have a certain electricity demand until the electricity price is above a certain point. An example could be that gas or oil would be used for heating if the energy price for that were cheaper than that of electricity.

2.1.5 Grid data

Information about the grid between the different areas in the system is specified with aggregated lines between the areas. Areas connected by the line, transmission capacity in each direction and energy loss in percent must be given. Transmission fees can also be specified where applicable. [12]

2.2 Strategy

2.2.1 Area aggregation

As discussed in chapter 2.1, the system is aggregated by dividing it into several areas and specifying production and consumption within each area in addition to transmission capacity between areas.

Equivalent reservoir

Energy from each reservoir within an area in the detailed model is added to one equivalent reservoir. The energy in each reservoir is found from multiplying reservoir volumes with the corresponding energy equivalents as discussed in chapter 2.1.1, with plant head as meters above sea level. Reservoir constraints that are specified in the detailed model are also converted to the equivalent model. [5]

Equivalent plant

The maximum capacity for all plants in an area is added to one equivalent plant. Discharge constraints are converted to $\frac{GWh}{week}$ and represented as minimum and maximum capacity constraints in the aggregate model, thus creating variable capacities for each week throughout the year. [5]

Energy inflow

Because all reservoirs are modeled as one large reservoir in the aggregate model, inflow has to be treated in a special way in order to avoid unrealistic reservoir utilization. Without special considerations, the large aggregated reservoir would not consider overflow and spillage in the real reservoirs from the detailed model. To avoid this situation, the real plants would be running at maximum capacity, and it is important that this is reflected in the aggregate model. Because of this, the distribution between storable and non-storable energy inflow in the aggregate model is calculated by simplified runs of the detailed model, as shown in equations (2.3) and (2.4). [5]

$$
\begin{aligned}
& \textbf{Non-storable inflow} = \\
& \quad \text{Generation due to non-storable inflow to the power systems} \\
+ & \quad \text{Generation due to minimum discharge and/or bypass constraints} \\
+ & \quad \text{Generation necessary to avoid spillage} \\
- & \quad \text{Energy used for pumping to avoid spillage}
\end{aligned} \tag{2.3}
$$

$$
\begin{aligned}
& \textbf{Storable inflow} = \\
& \quad \text{Sum production (including time-of-use purchase contracts)} \\
+ & \quad \text{Increase in reservoir volume (or - decrease in reservoir volume)} \\
- & \quad \text{Energy used for pumping}
\end{aligned} \tag{2.4}
$$

2.2.2 Water values

To determine when hydro power plants should run to maximize its profits, a value has to be placed on the water. There is no cost attached to using the water itself but it has a potential future value and it can therefore be looked upon as an opportunity cost. The potential future value is dependent on many factors including inflow to the reservoirs, market prices and load.

To calculate the water values an extensive computer program has to be used, one such is the EMPS model developed by SINTEF. The EMPS model uses a planning period of one to five years with a time step of one week. For every week the goal is to minimize the operation dependent costs of the next and all the following weeks' generation [5]. The function $J(x,k)$ gives the value of the total expected operation dependent costs from k until the end of the planning period. $J(x,k)$ is a function of reservoir level x and the time k. This cost dependent function can be derived from figure 2.4.

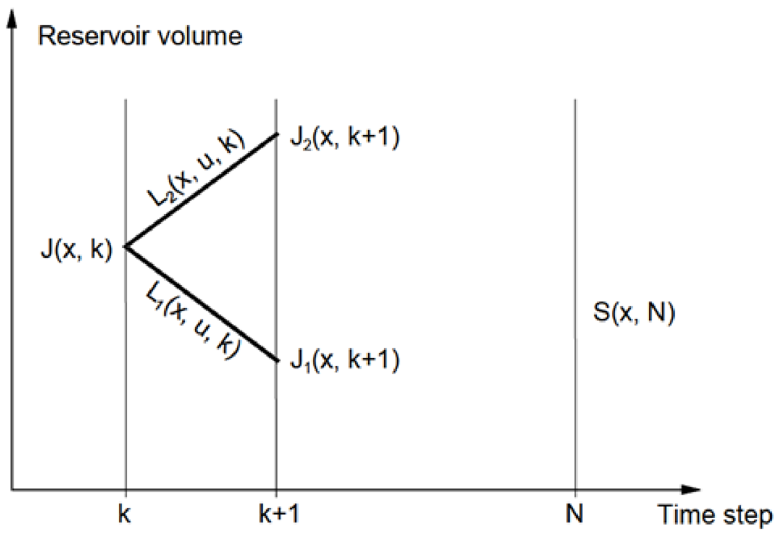


Figure 2.4: Planning period from week k to week N, [5]

The equation for the cost dependent function can then be formulated as (2.5).

$$J(x,k) = S(x,N) + \sum_{i=k}^{N} L(x,u,i) = L(x,u,k) + J(x,k+1) \tag{2.5}$$

Where $S(x,N)$ is the cost related to the change in the reservoir level. In other words the value at k minus the value at N as a function of the reservoir level, x, at the end of the planning period, N. $L(x,u,i)$ is the operation dependent cost going from i to $i+1$. u is the energy drawn from the reservoir to produce power p, $u = f(p)$.

The optimal handling of the reservoir is achieved when the total operation dependent costs are minimized with regard to the energy u used from the reservoir:

$$min_u J = min_u L(x,u,k) + J(x,k+1) \Rightarrow \frac{\partial J}{\partial u} = 0 \tag{2.6}$$

The result of this derivation, and thereby the optimal handling of the reservoir for period k is:

$$\frac{\partial L}{\partial u_k} = \frac{\partial J}{\partial x_{k+1}} \tag{2.7}$$

Where $\frac{\partial L}{\partial u_k}$ is the marginal operation dependent cost for, amongst others, sale and purchase. $\frac{\partial J}{\partial x_{k+1}}$ is the derivative of the total future operation dependent costs with regard to the reservoir level. This is the marginal water value.

This means that if the water value for one week is known the optimal water value the week before would be the same.

It is important to be aware of the fact that this derivation assumes that the inflow is known. To take into account the uncertainty related to the inflow this calculation has to be run with a number of different inflow scenarios. When using stochastic inflow the water value will have to be calculated for each of the different inflow scenarios as described above. This will give n different water values for each of the reservoir points that are

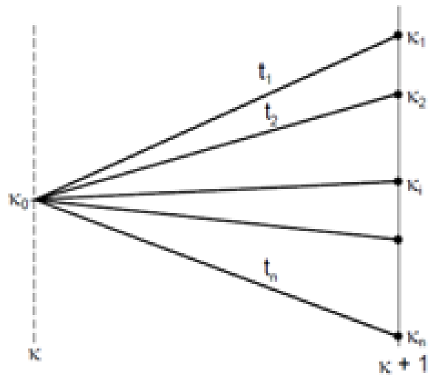


Figure 2.5: Basis of estimation the water value κ_0, [5]

calculated, κ_i. The optimal water value is then calculated with the formula:

$$\kappa_0 = \sum_{i=1}^{n} \kappa_i k_i \tag{2.8}$$

Where κ_i are the water values for the different inflow scenarios, k_i is the probability of the inflow scenario to occur and κ_0 the resulting optimal water value. This is illustrated in figure 2.5.

To get correct calculations of the water values it is important to model what happens when the reservoir is either full or empty correctly.

When the reservoir is full any inflow will be spilled, this means that the water is not worth anything and the water value at this point is set to zero. To avoid overflow generation can be increased above what the water value at the end of the week normally would tell you to produce. This means that the power will be sold at a lower price than the water value. The water value at the beginning of the week will be set to the price of the last sold kWh. [5]

An empty reservoir will result in the water value being equal to the last purchased or curtailed kWh. This means that the water value near the lower reservoir limit is highly dependent on the rationing or curtailment cost. [5]

To calculate the water values backward dynamic programming is used,

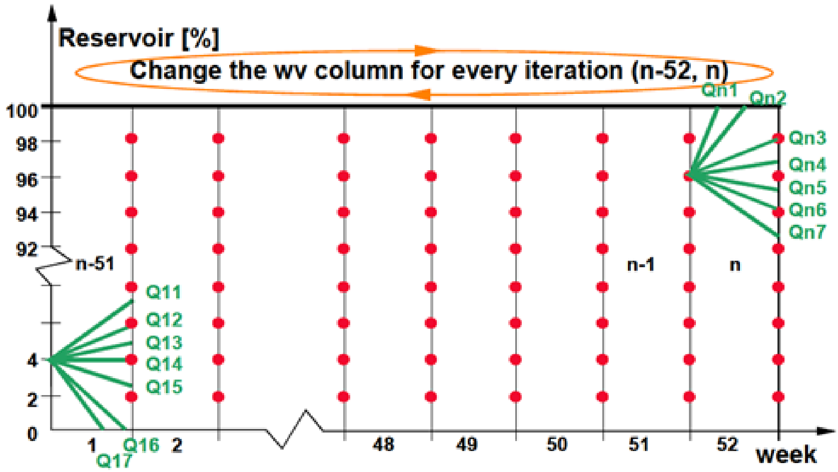


Figure 2.6: Water value iteration process, [5]

storing the derivative of the total costs instead of the total cost. To be able to solve (2.7) the water value at the end of the period needs to be known. This value will have to be estimated and if a significantly long enough planning period is chosen the present week water value will be independent of the estimated end water value. The estimated water value at the end is with other words not important as long as the time horizon is long enough. How long the time frame has to be is determined by the reservoir's degree of regulation, for a big degree of regulation a long time span is needed. A reservoirs degree of regulation is expressed by:

$$\alpha = \frac{R_{max}}{Q_a} \tag{2.9}$$

Where α is the degree of regulation, R_{max} is the maximum reservoir capacity and Q_a the annual inflow to the reservoir.

Instead of using a guessed starting value an iteration process is used. Initial water values are set and the water value is calculated back one year. The water value at the start of the year is then compared with the initial guess. If the deviation between them is above a certain tolerance the water values at the start of the year is set as initial values and the water values back a year is calculated again. This is done until a satisfactory precision is reached. The water values for the remaining years are then calculated. This process can be seen in figure 2.6.

2.3 Simulation

After the strategy phase and water value computations, a system simulation based on optimal power flow must be done in order to obtain the system operation state for different inflow scenarios. The system simulations will not give the accurate optimal solution, since future inflow is unknown. The water values are rather calculated in a way that gives the optimal system utilization in the long run, based on expected inflows, taking into account extreme conditions and their economic impact. The simulation logic is based on two steps: [5]

1. Optimal decision on the aggregate area level using a network algorithm based on the water values computed in the strategy phase. This is called area optimization.
2. Detailed reservoir drawdown in a rule 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.

2.3.1 Reservoir drawdown

In the aggregated simulation, a total production for each area is calculated. In the drawdown model, this production is distributed between the individual modules within each area. The detailed reservoir allocation from this production is not calculated by a formal optimization, but by a rule based strategy described below. Interaction between the aggregate area and the reservoir drawdown model can be seen in figure 2.7.

The reservoir drawdown strategy makes a distinction between different kinds of reservoirs:

- Buffer reservoirs that are run according to rule curves. These curves are model determined but may be modified by the user.
- Regulation reservoirs that are run according to a rule based strategy for the allocation of the stored energy in the system.

Buffer reservoirs are small reservoirs that have a low degree of regulation. That means that the ratio between reservoir volume and annual inflow is low, causing an empty reservoir to be filled up in a matter of weeks. The rule curve is a piecewise linear curve specifying reservoir level as a function of week number. This is a soft constraint which can be violated due to hard constraints such as maximum/minimum discharge.

Regulation reservoirs are all reservoirs that are not specified to be buffer reservoirs, and are run according to the allocation strategy between reservoirs. The drawdown model does not specify total amount of energy in the reservoirs, but the distribution of energy in regulation reservoirs based on total energy calculated on the aggregate level and specified energy stored in buffer reservoirs.

The reservoir drawdown model divides the year in two seasons, where each season has different strategies:

- **Filling season**, where inflow is larger than discharge.
- **Depletion season**, where discharge is larger than inflow.

Filling season

During the filling season, the main objective is to avoid spilling. This is achieved by keeping reservoirs at a level where they have equal damping, D, which can be seen on as a risk of spillage. [5] The damping is given as the difference between reservoir capacity. R_{max} and actual reservoir, R, divided by reservoir capacity and multiplied with the degree of regulation α, as seen in (2.10).

$$D = \frac{R_{max} - R}{R_{max}} \cdot \alpha \tag{2.10}$$

Depletion season

The strategy in the depletion season has two objectives: [5]

- The rated plant capacity must be available as long as possible to avoid emptying some reservoirs too early and causing a capacity deficit.
- At the end of the depletion season, the reservoirs should have equal relative damping according to (2.10) in order to minimize spillage in the coming filling season.

2.3.2 Interaction between area optimization and reservoir drawdown

Figure 2.7 shows a flow chart for the decision making process in the EMPS model. For a comprehensive description of the flow chart, see [5].

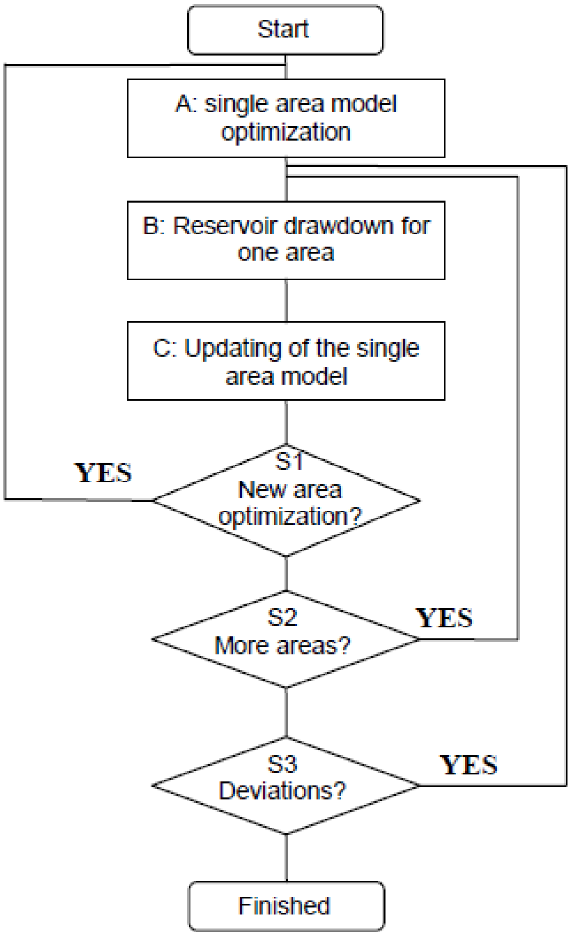


Figure 2.7: The weekly decision process in the EMPS model[5]

Chapter 3

Investment analysis

The functionality for investment analysis in the EMPS model is thoroughly described in Norwegian in [20]. This chapter gives a short English summary of the programs functionality.

3.1 Background

Investments in new production and transmission capacity in the Norwegian power system has the last few years gained a lot of attention. Discussions have among others been about whether the market is working as intended. Especially in regards to new investments three main questions have to be answered:

- Is it profitable?
- Geographical placement?
- Choice of technology?

When the Norwegian power system is analyzed, the EMPS model is frequently used. Earlier, there was no functionality for comparing different investment options in this model. It has, however, been used to manually test different options regarding technology, rating and localization. Manual analysis does however limit the number of scenarios due to the time consumed running the simulations. This new functionality makes it possible to compute a set of investments in the power system which is consistent with simulated power prices.

3.2 Functionality overview

The analysis is computed for a given future stage, i.e. the year 2020. The model calculates the investments in thermal power production, wind power production and in the transmission grid. Sequential dynamic analysis is also possible. This means that the results from e.g. 2020 can be used in the simulations for 2030.

Figure 3.1 shows the structure of the investment model. The left side of the figure shows the input into the model, the iterative algorithm is located in the middle and the right side shows the results.

All input data for the system has to be adapted to the future stage and specified according to point 2 in figure 3.1. The user also has to specify what investment options there are and in addition the technical and economical information for these alternatives (see point 5). This information has to be specified before the start of the analysis.

When the investment analysis is run the data for the future stage of the system is loaded and the EMPS model calculates the optimal operation of the system. Some of the results of this simulation are the weekly prices in all the areas of the model. These prices together with the predefined investment options are then used to calculate the profitability of the different investment alternatives. If the profit is high enough for a given alternative then the program will invest in this alternative in the first iteration. In the next iteration the capacity of the investment is increased by a predefined amount. If the profit for an iteration is negative the capacity is reduced compared to the previous iteration. If the profit of a capacity increase is positive but lower than a predefined minimum profit required for an investment the capacity is set to the size of the previous iteration. This predefined minimum profit

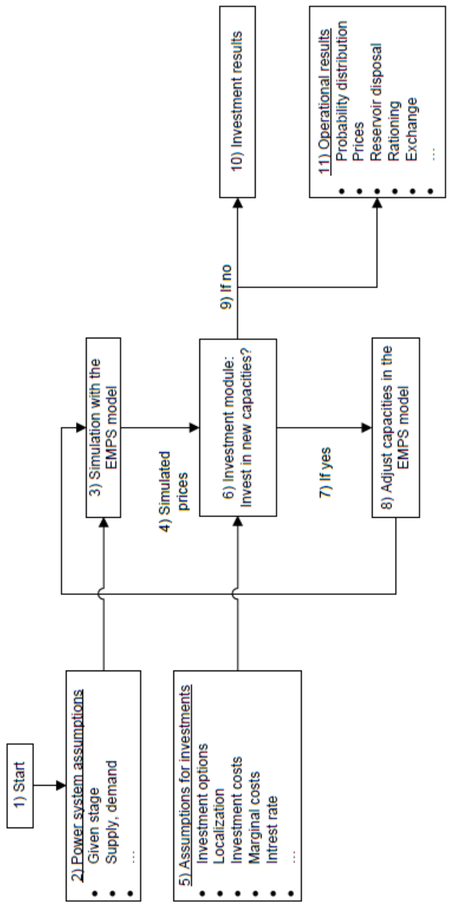


Figure 3.1: Investment functionality in EMPS

has to be big enough compared to the change of capacity to make sure that the investment analysis converges.

If the capacities are changed the EMPS model is run again and new weekly prices are found. This process continues until the profit of investing in additional capacity is positive but below the minimum profit threshold for all investment alternatives.

The output from the investment analysis is a file that shows the iterative solutions in addition to the final investment result for each investment alternative.

3.3 Mathematical description

Table 3.1 contains all the symbols used in this chapter to describe the mathematical calculations used in the investment analysis model. [20]

Table 3.1: List of symbols

Symbol		**Description**	
Array			
J	=	Simulated inflow years (i.e.)	J=1931,...,2005
I	=	Simulated weeks	I=1,...,52
Indices			
i	=	Week	i $\in I$
j	=	Inflow year	j $\in J$
k	=	Investment alternative	
l	=	Model number (for wind power)	
m^k	=	Area for investment alternative k	
n^k	=	Transmission line in investment alternative k, goes between area m^k and n^k	
Other			

Continued on Next Page...

Table 3.1 – Continued

Symbol		Description	
N	=	Number of simulated years (i.e. elements in J)	
p_{i,j,m^k}	=	Simulated weekly prices from Samkjøringsmodellen in area m^k	(EuroCent/kWh)
p_{i,j,n^k}	=	Simulated weekly prices from Samkjøringsmodellen in area n^k	(EuroCent/kWh)
c_k	=	Marginal production cost	(EuroCent/kWh)
l_k	=	Annual investment cost	(€/MW/year)
z_k	=	Investment profit required to increase capacity from one iteration to the next, as a part of the investment cost. This comes in addition to the demand of normal expectation when calculating the annual investment cost.	(Share)
t_{m^k,n^k}	=	Transmission loss between areas m^k and n^k	(Share)
$y_{i,j,m^k,l}$	=	Wind power production	(GWh/week)
$\overline{y}_{m^k,l}$	=	Installed wind power	(MW)
u_{i,j,m^k}	=	Utilization factor for wind power	(Share)
π_k	=	Expected value for the profit of alternative k	(€/MW/year)

To determine whether an investment pays off the marginal profit of adding one extra MW of capacity is calculated. The marginal profit is calculated using the weekly prices from the last iteration. For thermal power the marginal profit is calculated with equation 3.1.

$$\pi_k = \sum_{\substack{i \in I \\ j \in J}} max\left\{0; p_{i,j,m^k} - c_k\right\} \cdot \frac{24 \cdot 7 \cdot 1000}{N \cdot 100} - I_k \tag{3.1}$$

$p_{i,j,m^k} - c_k$ is the profit of adding an extra MW of thermal power. This is multiplied with $24 \cdot 7$ to get the weekly profit and with $\frac{1000}{100}$ which is the factor to convert from EuroCent to Euro and from $\frac{kWh}{h}$ to $\frac{MWh}{h}$. Further it is summed over all simulated weeks and years and then divided by the years simulated. The annual investment cost I_k is in the end subtracted so that the equation shows the change in profit $\frac{€}{year}$ for investing in an additional MW.

The program does not calculate the annual investment cost so this has to be calculated manually by the user and specified in the input files. As previously mentioned, if the profit is positive and above the predefined required profit z_k an investment will be made. If it is positive but below z_k the capacity will be kept at the same level as the previous iteration and if it is negative it will be decreased below that of the last iteration.

For wind power two equations are needed. First the expected average production in a given week if one extra MW is added has to be calculated using equation 3.2.

$$u_{i,j,m^k} = \frac{\sum_l y_{i,j,m^k,l} \cdot 1000}{\sum_l \overline{y}_{m^k,l} \cdot 24 \cdot 7}, \qquad u_{i,j,m^k} \in [0,1] \tag{3.2}$$

To be able to use 3.2 there has to be an initial wind power capacity in the area where it is invested. If there is no wind power production in that area a marginal capacity has to be added. The marginal profit is calculated using equation 3.3.

$$\pi_k = \sum_{\substack{i \in I \\ j \in J}} p_{i,j,m^k} u_{i,j,m^k} \cdot \frac{24 \cdot 7 \cdot 1000}{N \cdot 100} - I_k \tag{3.3}$$

The profit of building additional transmission capacity is determined by the price difference between the two areas it is built between. The marginal profit for 1MW of additional transmission capacity is given by equation 3.4.

$$\pi_k = \sum_{\substack{i \in I \\ j \in J}} max \left\{ \begin{array}{c} 0; \\ \left[p_{i,j,m^k}\left(1 - t_{m^k n^k}\right) - p_{i,j,n^k}\right]; \\ \left[p_{i,j,n^k}\left(1 - t_{n^k m^k}\right) - p_{i,j,m^k}\right]; \end{array} \right\} \frac{24 \cdot 7 \cdot 1000}{N \cdot 100} - I_k \tag{3.4}$$

The marginal profit is calculated by subtracting the weekly prices in the areas from each other, multiplied by the transmission loss. It is then multiplied with $\frac{24 \cdot 7 \cdot 1000}{N \cdot 100}$ to convert it to $\frac{€}{MW \cdot year}$. Finally the annual investment cost is subtracted.

3.4 Convergence in the investment algorithm

It is important to note that the procedure shown in figure 3.1 will not necessarily converge. The program can possibly iterate between several solutions where balance requirements are not satisfied.

It is important that a big enough minimum required profit z_k compared to the change in capacity between two iterations is needed. The relation between these two variables has to be considered when specifying the initial investment data. Trial and error can also be used to find this relation.

Another problem is how to evaluate one investment's profitability when it relies upon another investment. For instance can an increase in production capacity require additional transmission capacity.

One way of getting around this problem is to specify in the input files the increase in transmission capacity that is needed for a given increase in production capacity. This way the cost of building additional transmission capacity increases the required annual investment costs needed for the investment alternative. The potential increase in profits is however not included when calculating the profits of the production capacity increase. The reasoning behind this is that the transmission capacity expansion is required for the area prices from the last simulations to be useable. If additional increase in transmission capacity is considered then this can be specified as its own investment alternative, evaluated by equation 3.4.

This will make sure that the program avoids iteration between solutions where the capacity for production and transmission works against each other.

Another way of handling this problem is to add increased capacity in every other iteration. In these iterations only a possible increase in transmission capacity is evaluated. This means that decreased transmission capacity and change in production capacity is not evaluated. This is done to make sure that the algorithm does not rotate between different solutions. It is also not believed that this will lead to too big increases in transmission capacity as that would lead to negative marginal profit and reduced transmission capacity in the other iterations.

Chapter 4

Improvements

To improve the investment analysis a few changes was made to the program. The changes made are described in this chapter.

4.1 Maximum capacity

One of the new features was to add an option to the user to set maximum capacities for the different investment alternatives e.g. in the case of a wind farm that has a limited amount of space to be built on. If the user wants to set a maximum capacity then this has to be specified in the input files. The program acts as if there is no limit to the maximum capacity if this option is set to zero. Table 4.1 shows how the input files have to be specified after this addition, in this case the investment alternative of a gas power plant has been limited to a maximum of 600 MW.

4.2 Price segments

Each week in the EMPS model are split into different price segments representing the demand in the different parts of a week, e.g. middle of the day and during the night. The investment analysis however used average weekly prices to calculate profits. This means that price variations between e.g.

Table 4.1: Investment file for thermal investments

```
Omraade:  OSTLAND
Antall investeringer:  1

1.
Typenummer:  13  Terskel:  0.20   Jump:  200
Margkost:  3.20  Inv.kost:  3200  Startkap:  0  Makskap:  600

Antall inkluderte nettinvesteringer:
0
```

night and day are not considered, something which is very important when calculating the profit of a cable to Central Europe. The implementation is further specified in Steinar Beurlings master report [3].

Chapter 5

Input data

5.1 General

The model is split in 34 different areas. 13 of the areas only contain wind power production. There is no load or any other kind of production in these areas. The wind power areas are connected to their "normal" areas by transmission lines with endless transmission capacity. The remaining 21 areas contain both production (hydro or thermal, and in Denmark also wind) and consumption equal to the area they are representing. The areas defined can be seen in B.1. The area numbering is based on how they are numbered in the EMPS model.

Geographical location of the areas in the model can be seen in figure 5.1.

The transmission line representation is, as seen in figure 5.1, very aggregated. It is represented with 32 transmission lines and in addition 13 transmission line with infinite capacity connecting wind power areas with the normal areas in the same location. The lines can be seen in table B.2.

5.2 Production, consumption and transmission

Production and Consumption, with all underlying data such as capacities, reservoirs, inflows etc. is data given in the model upon receiving it from

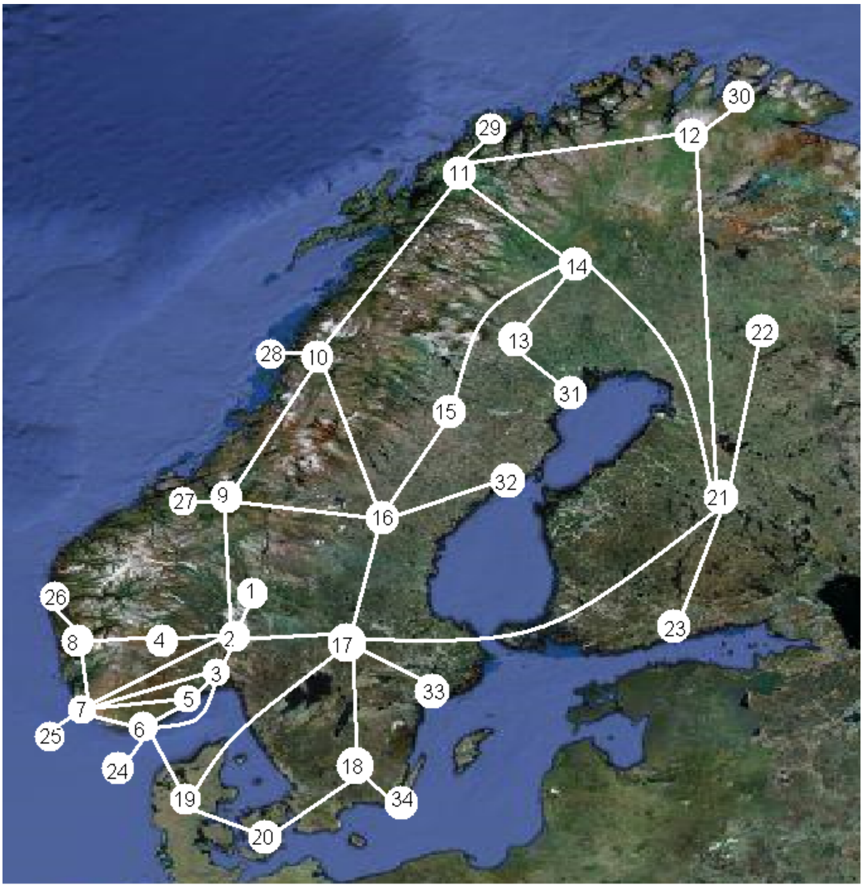


Figure 5.1: Areas in the model

SINTEF Energy Research. These data are from 2009 edition of the EMPS model, and should therefore be up to date. This is also the case for transmission capacities.

5.3 Investment parameters

When performing an investment analysis the investment cost of the different investment alternatives have to specified. The investment analysis requires the investment costs to be specified in $\frac{EuroCent}{kW \cdot year}$ To calculate this the investment cost is annualized using equation 5.1.

$$A = \frac{I \cdot (i+1)^n}{(i+1)^n - 1} \tag{5.1}$$

where:

A =	Annual investment cost
I =	Initial investment cost
i =	Interest rate
n =	Number of years

5.3.1 The cost of wind power

Table 5.1 shows the investment costs for a typical onshore wind farm.

Onshore wind	
Investment costs, $\frac{€}{MW}$	1600000 [4]
Interest rate [6]	6.5%
Payment period	25 years
Annual investment costs, $\frac{€}{MW}$	Interest rate
O&M costs, $\frac{€}{MWh}$	2 [8]

Table 5.1: Investment costs for wind power

5.3.2 Wind power utilization

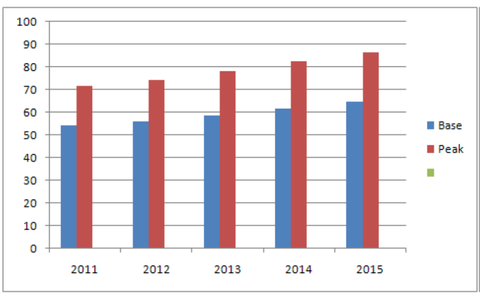
Wind power farms have a varying efficiency depending on the wind conditions where it is located. Utilization factor, given in GWh yearly per MW of installed capacity, is found from Norwegian Water Resources and Energy Directorate (NVE) [19] for areas in Norway. Utilization factors for wind farms planned in Sweden is found on Statkrafts web-pages [1]. The complete set of utilization factors used in this report can be seen in table C.1 and C.2.

5.4 Europe

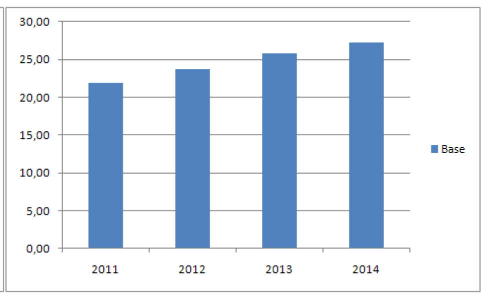
5.4.1 APX

The Netherlands is modeled by financial contracts that try to emulate the import/export on the NorNed cable. The financial contracts are so called price dependant contracts. This means that contracts can be specified to purchase or sell power at given prices.

To model the prices used by the price dependant contracts in the Netherlands statistic prices from the APX ENDEX Future Power market were used [2]. The future prices for base and peak load are shown in figure 5.2.



(a) Power



(b) Gas

Figure 5.2: Future power and gas prices in the Netherlands

The figure 5.2a shows that the power prices in the Netherlands are expected to slowly increase over the next few years. One reason for this is probably that the prices of fossil fuels are expected to increase slowly as well, shown in figure 5.2b. Since most of the power production in the Netherlands are based on fossil fuels this would lead to a similar increase in the power prices. No prices for the off-peak hours where found on the future power markets for both APX and EEX so the price at night was set to the same value that was used in Statnetts license application for the NorNed cable at around $\frac{21€}{MWh}$ [14].

One important factor that has to be considered is that the EMPS model usually produces prices that are somewhat below the actual prices in the real market. One of the reasons being that the start/stop conditions in the Nordic market are not modeled satisfactory. The price dependant contracts in the Netherlands would therefore have to be adjusted so that the cable will export most of the time during a wet year and import most of the time during dry years.

The EMPS model uses seven different so called price segments to model a week. These seven price segments have different load profiles and thereby differentiate between i.e. night and peak hours during the day. The price segments used in the model can be seen in table 5.2.

Table 5.2: List of price segments

Nr. #	**Name of segment**	**Description**	**Hours per week**
1	HD	High day	30
2	HK	High evening	10
3	LD	Low day	50
4	N	Night	30
5	HELG	Weekend	34
6	N-LOR	Night Saturday	7
7	N-SON	Night Sunday	7

The prices in "Sørlandet" can be seen in figure 5.3. Together with the price information in the Netherlands and the price segments six contracts were formulated.

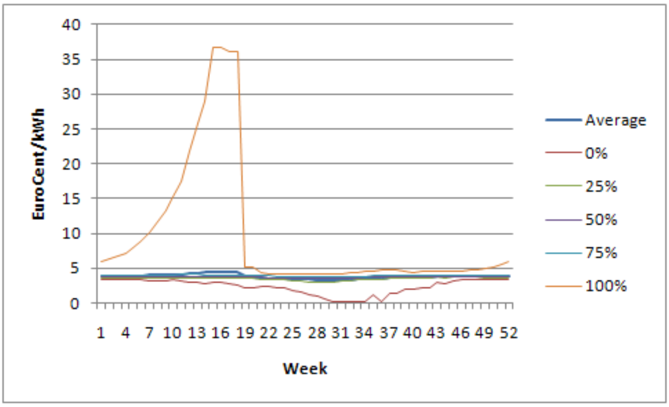


Figure 5.3: Prices in "Sørlandet", percentiles [EuroCent/kWh]

Table 5.3: List of price dependant contracts, the Netherlands

Nr. #	Type	Price	Amount	Price segments
1	IMPORT	2.47 EuroCent/kWh	122.64 GWh	4, 6, 7
2	IMPORT	4.00 EuroCent/kWh	122.64 GWh	2, 3, 5
3	IMPORT	5.50 EuroCent/kWh	122.64 GWh	1
4	EXPORT	2.57 EuroCent/kWh	122.64 GWh	4, 6, 7
5	EXPORT	4.05 EuroCent/kWh	122.64 GWh	2, 3, 5
6	EXPORT	5.60 EuroCent/kWh	122.64 GWh	1

The six contracts were split into 3 sets (one import and one export in each set). One set for peak load, one for base and one for off peak. The peak contract set was assigned to HD (high day). The base set was assigned to HK (high evening), LD (low day) and HELG (weekend). The off peak set was assigned to N (night), N-LOR (night Saturday) and N-SON (night Sunday). The prices used in the contracts are all somewhat lower than the real prices in the APX market and this is done, as previously mentioned, because the model produces lower prices than the real prices in the market.

The power flow in the NorNed cable can be seen in figure 5.4. The behavior of the power flow in the extreme scenarios, i.e. wet and dry years can be seen as the 0% and 100% and the bold line shows the average of all the inflow scenarios. The average line shows that the flow normally goes from Norway to the Netherlands, with some seasonal variation. It is however

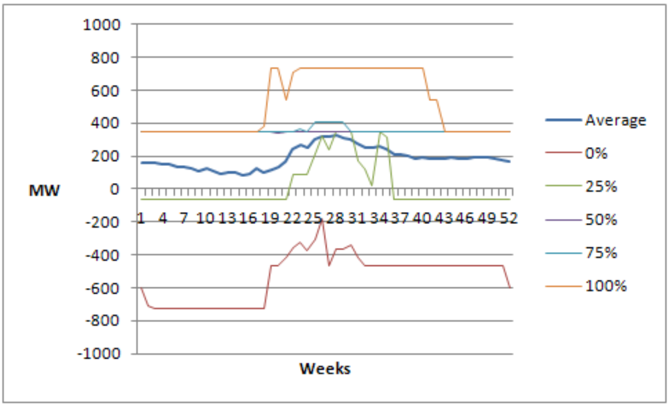
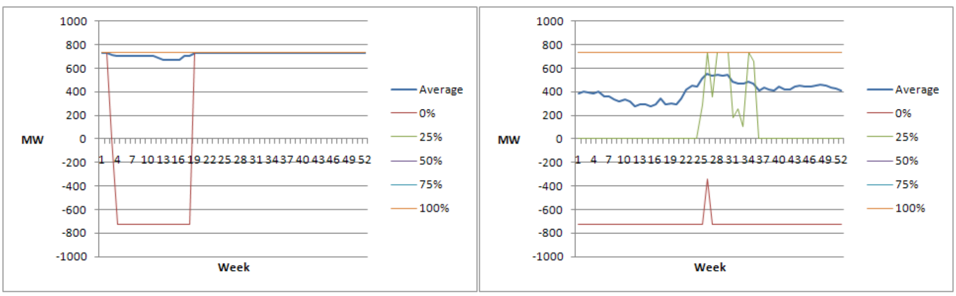


Figure 5.4: Percentiles of the power flow in the NorNed cable [MW]

important to note that this shows the average of the price segments for each week. The flow in the different price segments are in fact far from this average value. Figures 5.5, 5.6 show the flow in three of the price segments. The maximum capacity of the NorNed cable was set to 730 based on data from Nordpool.



(a) Price segment 1 (b) Price segment 3

Figure 5.5: Percentiles of the flow in the NorNed cable

The flow in the NorNed cable for the price segments show that during the peak hours of a week the flow is almost always from Norway to the Netherlands. The only exception is in extreme dry years in Norway. During the low day price segment the flow is also most of the time towards the

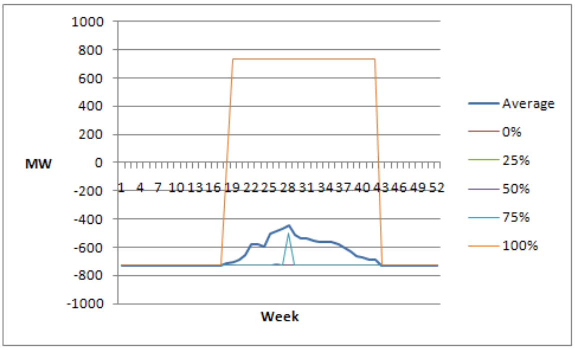


Figure 5.6: Percentiles of the flow in the NorNed cable, price segment 4 (Night)

Netherlands, but somewhat lower than in the peak hours. The export to the Netherlands is the greatest during the summer when the prices in Norway are the lowest. In price segment 4, during the night, the flow is in the opposite direction with the exception of very wet years during the summer. The importance of modeling the flow on the NorNed cable with different price segments and not use the average value will be apparent when the profitability of DC links between the Nordic model and Northern Europe are calculated. The profit of a transmission line is calculated using the equation 3.4. As it can be seen the price difference between two areas is the determining factor, and this price difference is much better modeled with price segments than with just an average price. The results of price segment 6 and 7 are almost identical to price segment 4 and price segment 2 is almost identical to price segment 3.

Another impact of the NorNed cable can be seen in the prices in the area it is connected to in Norway, "Sørlandet". Figure 5.3 shows some of the percentile of the prices in Vestsyd without the NorNed cable. Figure 5.7 shows the same percentiles with the NorNed cable. The impact of the cable can be seen in the 0% and the 100% percentiles. In a dry year situation the cable allows Vestsyd to buy relatively cheap power from the Netherlands and thereby reducing the prices somewhat. In the opposite scenario where Norway is overflowing with cheap hydro power the cable can be used to sell

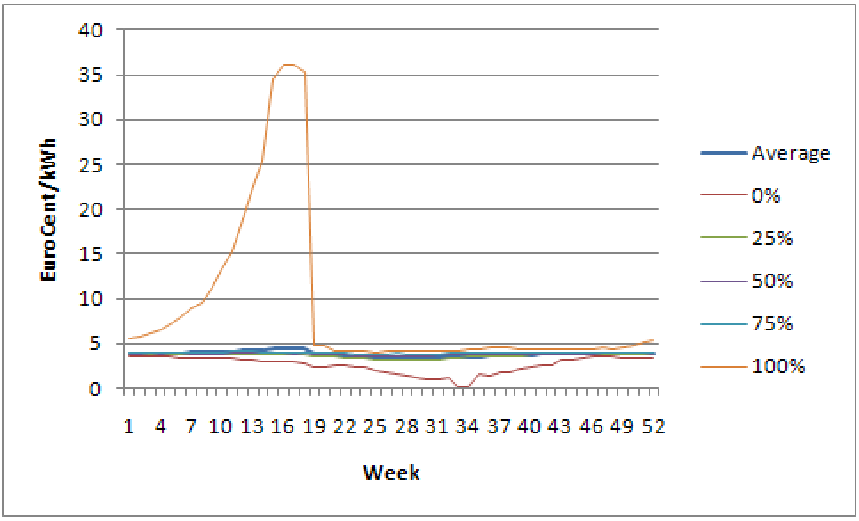


Figure 5.7: Percentiles of the prices in "Sørlandet" with the NorNed cable [EuroCent/kWh]

all the excess cheap power to the Netherlands and thereby drive the prices up.

Another assumption that is made is that the prices in the Dutch market is not affected by the import from Norway. This is however not the case as the Dutch energy market is smaller than the Norwegian and as previously shown the NorNed line does have an impact on the prices in Norway.

5.4.2 EEX

The German market was modeled the same way as the Netherlands. The prices used were taken from the EEX derivatives market [7] and they can be seen in figure 5.8

The future price development for the German market is slightly higher than it was for the Netherlands, see figure 5.2. The contracts were therefore set to be slightly higher in Germany compared to the contracts in the Netherlands. The contracts can be seen in table 5.4

Germany is connected to the Nordic market in three places. The con-

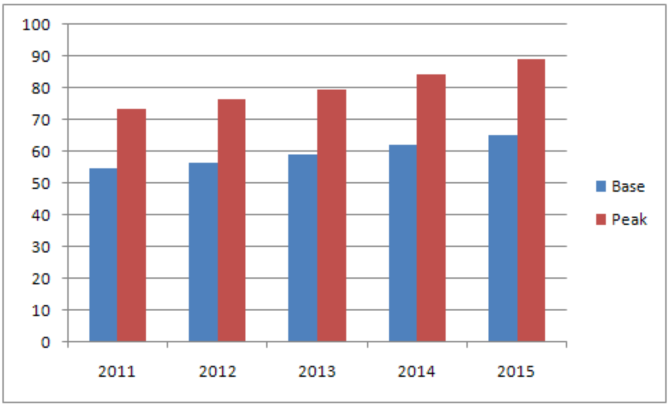


Figure 5.8: Future power prices in Germany

Table 5.4: List of price dependant contracts, Germany

Nr. #	Type	Price	Amount	Price segments
1	IMPORT	2.47 EuroCent/kWh	122.64 GWh	4, 6, 7
2	IMPORT	4.05 EuroCent/kWh	122.64 GWh	2, 3, 5
3	IMPORT	5.60 EuroCent/kWh	122.64 GWh	1
4	EXPORT	2.57 EuroCent/kWh	122.64 GWh	4, 6, 7
5	EXPORT	4.10 EuroCent/kWh	122.64 GWh	2, 3, 5
6	EXPORT	5.70 EuroCent/kWh	122.64 GWh	1

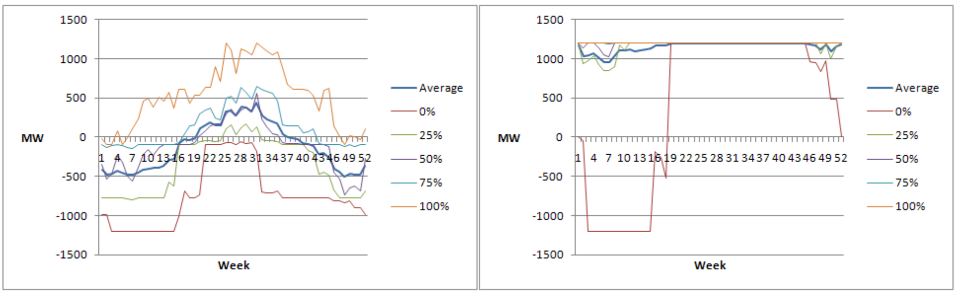
Table 5.5: List of connections to Germany

From	To	Capacity to [MW]	Capacity from [MW]
Denmark West	Germany	1500	950
Denmark East	Germany	550	550
Sweden	Germany	1200	1200

nections can be seen in table 5.5.

It is important to note that the connection between Sweden and Germany in reality only is 600MW, but there is in addition a cable going from Sweden to Poland of the same size that has been included into this connection because the prices in Poland are fairly similar to the prices in Germany [18] and because the connection to Poland is small compared to the total connection from the Nordic market to Germany.

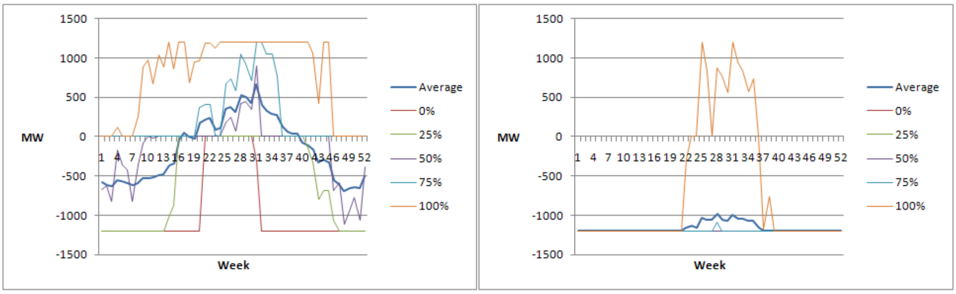
The resulting flows on the line between Sweden and Germany can be seen in the figure 5.9 and figure 5.10



(a) Weekly prices (b) Price segment 1

Figure 5.9: Percentiles of the flow on the cable from Sweden to Germany

These graphs show that the flow as an average of all the price segments goes from Sweden to Germany during the summer, but in the opposite direction during the winter. The plot of the peak hours (price segment 1) over a year show that the flow goes from Sweden to Germany at nearly maximum capacity for most of the year for all but the 0% percentile. The price segment 3 plot, base load, shows similar results to the average of all price segments with power flowing to Sweden during the winter and towards



(a) Price segment 3

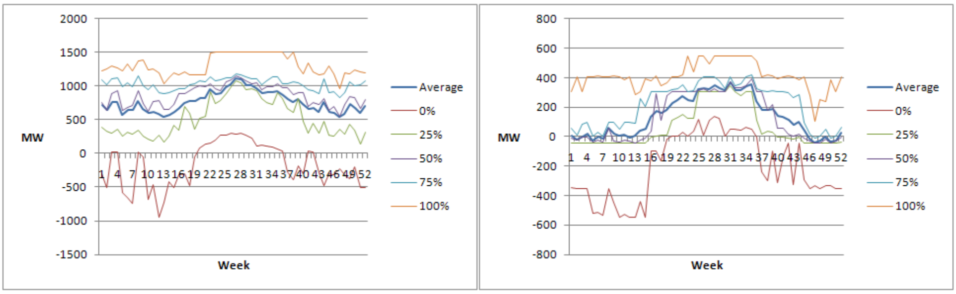
(b) Price segment 4

Figure 5.10: Percentiles of the flow on the cable from Sweden to Germany

Germany during the summer. The plot showing price segment 4, night, shows import into the Nordic system from Germany. This is due to the low prices in Germany during the night. Only in the case of a very wet year in the Nordic system would the flow during the night go from Sweden to Germany, as seen in the 0% percentile. The reason for why the prices in Germany and the Netherlands during the night are so low is that thermal generation, especially nuclear power, has a significant start/stop price and also startup/shutdown time. So it costs some of those production units less to generate during the night and sell at a low price than it costs them to turn on and off the power plant. The results of price segment 6 and 7 are almost identical to price segment 4 and price segment 2 is almost identical to price segment 3.

The lines from Denmark East and West to Germany show similar results to the line from Sweden to Germany. The average flows for all inflow scenarios are shown in figure 5.11.

The implementation of the cables to Germany into the Nordic system already connected to the Netherlands had an impact on the flow from Norway to the Netherlands. Previously the flow on the NorNed cable did, in average, flow mostly towards the Netherlands. Now however the results showed that the average flow during the winter is closer to zero, and the flow during the summer has also decreased. The new flow, average of all the price segments,



(a) Denmark West - Germany (b) Denmark East - Germany

Figure 5.11: Percentiles of the flows on the cables from Denmark to Germany using average weekly prices

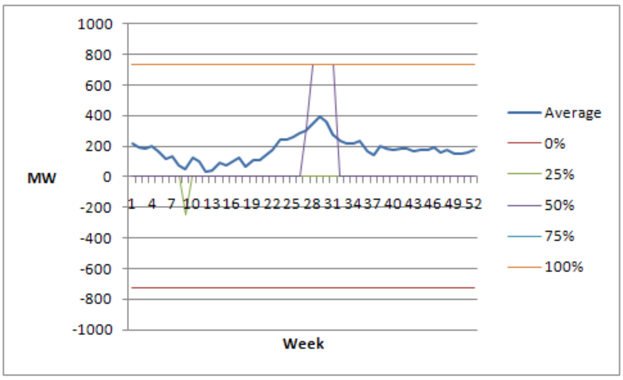


Figure 5.12: Percentiles of the flow in the NorNed cable, price segment 3, with Germany [MW]

can be seen in figure 5.13. The flow during the night is still almost always towards the Netherlands and the flow during peak hours is still in all but the 0% towards Norway. The flow during base load is the one that has dropped and the new flow in this price segment can be seen in figure 5.12.

A reason for this might be that since the price dependant contracts in Germany are set higher than in the Netherlands the Nordic market would rather sell all they can to Germany and import more from the Netherlands to cover its own load.

The connections to the Netherlands and Germany did also have an im-

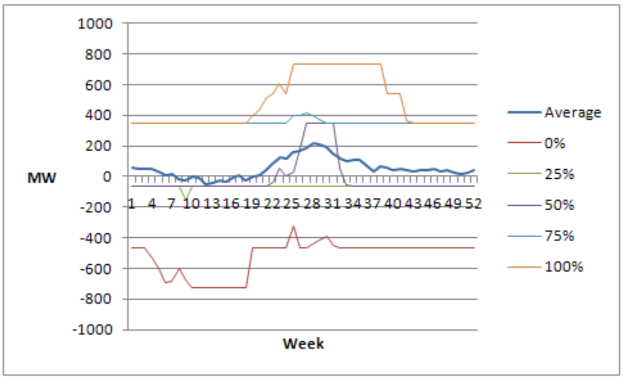
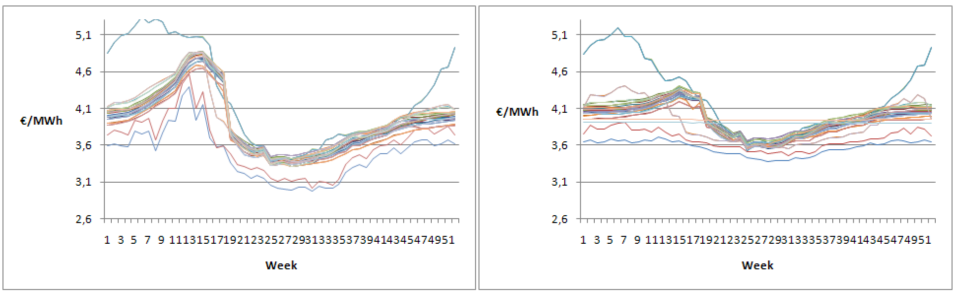


Figure 5.13: Percentiles of the flow in the NorNed cable using average weekly prices, with Germany [MW]

pact on the prices in the Nordic market. Figure 5.14 shows the prices in the all areas in the Nordic model with and without connections to the Netherlands and to Germany.



(a) No connections (b) Including the Netherlands and Germany

Figure 5.14: Prices in all areas, using the average of all inflow scenarios and average weekly prices

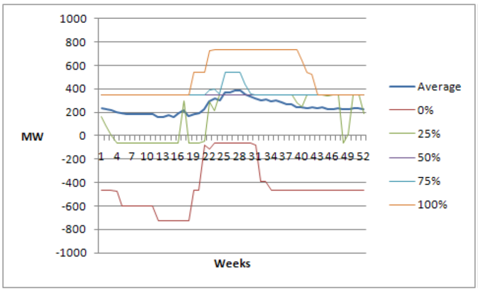
5.4.3 Sensitivity analysis

When modeling the import/export to e.g. the Netherlands with price dependant contracts the determining factor will naturally be the prices used in those contracts. To test how sensitive the flow on the line between the Netherlands and Norway was the price dependant contracts where increased/decreased with 5%, 10% and 25%.

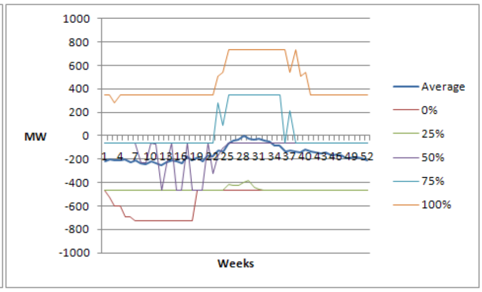
Figure 5.15 shows the impact the new prices have on the flow in the NorNed cable. It is evident in the 5% increase and decrease that the change in price has a big impact on the import/export. With the original contracts in place the average plot of all scenarios was at 0 during the winter and rose up to 200 MW during the summer. Increasing the contracts with 5% however resulted in the flow to increase with 200MW throughout the year. Reducing the contracts by 5% resulted in a similar drop, now reducing it to -200 MW during the winter and 0 MW in the summer.

Changing the price dependant contracts with 10% also results in significant changes to the import/export. An increase of 10% increases the average import to the Netherlands to 300 MW during the winter and 500M MW in the summer. A reduction of 10% results in an export from the Netherlands to Norway for about -400 MW during the winter and -200 MW during the summer. Significant changes can also be noticed in the different percentiles.

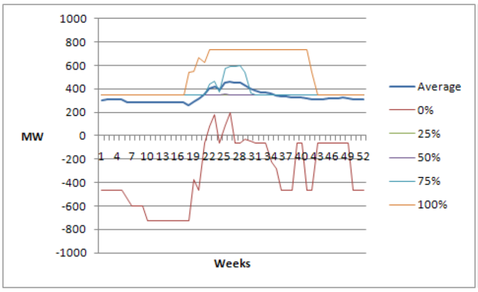
The difference between changing the price dependant contracts by 10% and 25% are not that big for the average flow. The percentiles, most notably the 100% and the 75% percentiles when reducing the contracts by 25%. The 0% percentile changes by a lot when increasing the contracts.



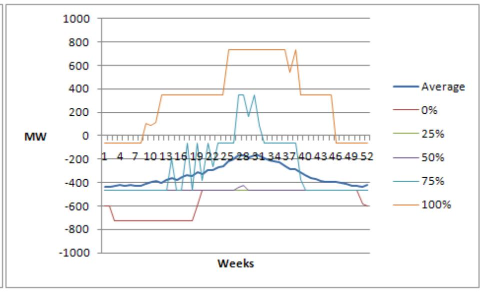
(a) 5 % increase



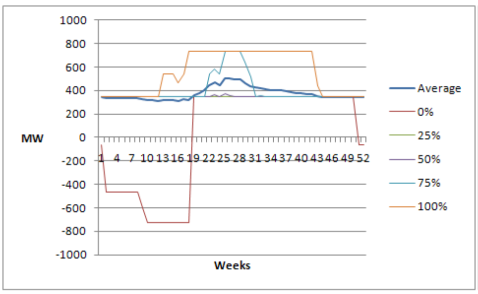
(b) 5 % decrease



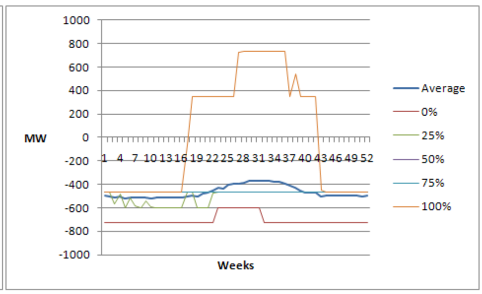
(c) 10 % increase



(d) 10 % decrease



(e) 25 % increase



(f) 25 % decrease

Figure 5.15: Sensitivity analysis of the price dependant contracts in the Netherlands, in percentiles

Chapter 6

Simulations

This chapter contains case studies done using the investment analysis functionality for the EMPS model.

6.1 Calibration

Before any investment analysis simulations were carried out the model was calibrated using an automatic script provided by SINTEF. The calibration aims to achieve three goals [11].

- Avoid to much spillage (lost water)
- Avoid empty reservoirs (rationing / load shedding is expensive)
- Utilize capacity for moving water from summer to winter

The script procedure is to run a lot of simulations with stepwise changes in the feedback factor, form factor and the elasticity factor for each area. For each change in these factors the scripts calculates the socio-economic surplus with the goal of achieving it as high as possible.

The calibration of a model is a very time consuming procedure as has 20 rounds that run at least twice for each of the areas with hydro power (16), a total of at least 640 simulations.

6.2 Additional transmission capacity to the Netherlands

This case will look at the profitability of investing in additional transmission capacity to the Netherlands.

6.2.1 Input data

The input file for transmission grid investments is shown in figure 6.1.

```
Inputfil for informasjon om investeringer i transmisjon

Antall linjer:
49

Linje 1 i maskenett.data:
"'MASKENETT',7,30,10,50,30,34,7,7"

Antall transmisjonslinjer hvor investeringer er aktuelt:
1

1.
Linjenummer:    46          Terskel:       0.30        Jump:              200          Maxkap:              0
Inv.kost:       4280        Startkap_tur:  730         Startkap_retur:    730



X
X
Et par ekstra linjer
```

Figure 6.1: Input file for transmission grid investments

The calculation of the input data for the investment is based on the license application for the NorNed cable in 2004 [15] and can be seen in table 6.1.

Table 6.1: Input data for the transmission capacity investment to the Netherlands

Investment cost	4 600 MNOK
Investment cost	575 Mill €
Interest	4.5%
Payment period	40 years
Annual investment cost	4280 $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$

No other transmission investment alternatives were added, and there was also no realistic thermal or wind investments specified. The investment analysis program requires at least one of each investment to be specified to prevent it from crashing, so these were specified with an unrealistically high investment cost to prevent investments from happening.

6.2.2 Simulation

The results from different iterations of the investment analysis are shown below.

```
Runde:  1(A)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   7159.3   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8354.6   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   9065.1   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8078.1   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   9152.8   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15471.9   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:       0 (MW)   Avanse:  56639.5   Inv.kost.  :  4280
```

Figure 6.2: Iteration 1

The profit of adding an addition MW from "Sørlandet" to the Netherlands is 56639.5 which is clearly higher than the annual investment cost. An investment of 200MW will be carried out.

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Runde: 10(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   7207.0   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8350.6   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   9086.9   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8092.7   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   9167.6   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15477.1   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:    1800 (MW)   Avanse:  25994.9   Inv.kost.  :  4280
```

Figure 6.3: Iteration 10

After 10 iterations and an investment of 1800MW that there is still a significantly higher profit than investment cost.

Figure 6.4 shows the final result of the investment analysis. The results show that it would be profitable to invest in a cable of 3400 MW, five times as much as size of NorNed.

The profit for investing in an additional MW of transmission capacity when 3400 MW is already build is 19051 $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$ which would suggest that another investment should be done. Investing in another 200MW of trans-

```
Runde: 18(B)

Termisk kapasitet:
( 2) OSTLAND      Typenr.: 13    Kapasitet:     0 (MW)   Avanse:    7524.1   Inv.kost.:  320000.
( 7) VESTSYD      Typenr.: 13    Kapasitet:     0 (MW)   Avanse:    8701.3   Inv.kost.:  320000.
( 9) NORGEMIDT    Typenr.: 13    Kapasitet:     0 (MW)   Avanse:    9362.0   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI   Modulnr.: 500 Kapasitet:     1 (MW)   Avanse:    8157.2   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE   Modulnr.: 500 Kapasitet:     1 (MW)   Avanse:    9241.6   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM   Modulnr.: 500 Kapasitet:     1 (MW)   Avanse:   15595.0   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND    - NEDERLAND      Ekstra:    3400 (MW)   Avanse:   19040.6   Inv.kost.   :   4280
```

Figure 6.4: Final investment result

mission capacity does however result in a profit of 0 $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$. The reason why the profit drops to 0 might be that the price difference between the Netherlands and "Sørlandet" has decreased to zero. Looking at the prices in those two areas at 3400 MW of invested capacity, figures 6.5 and 6.6, it can be seen that there is indeed a little difference in prices which explains the profit. Looking at figure 6.7 and 6.8 one would expect the prices to be almost identical. There is however still a difference between the prices in the two areas.

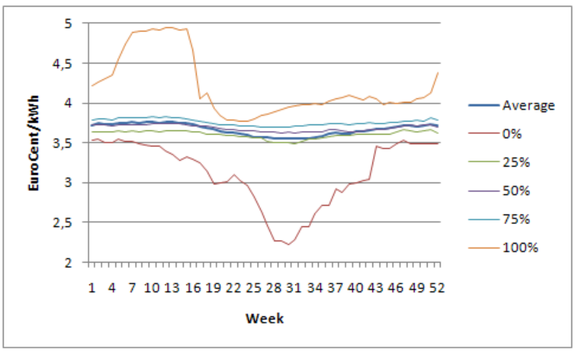

Figure 6.5: Prices in "Sørlandet" with a transmission capacity investment of 3400 MW

The figures 6.5, 6.6 show one of the main reason for investing in transmission capacity to systems outside of the Nordic. In a dry year situation where previously the price for one kWh of electricity would rise as high as

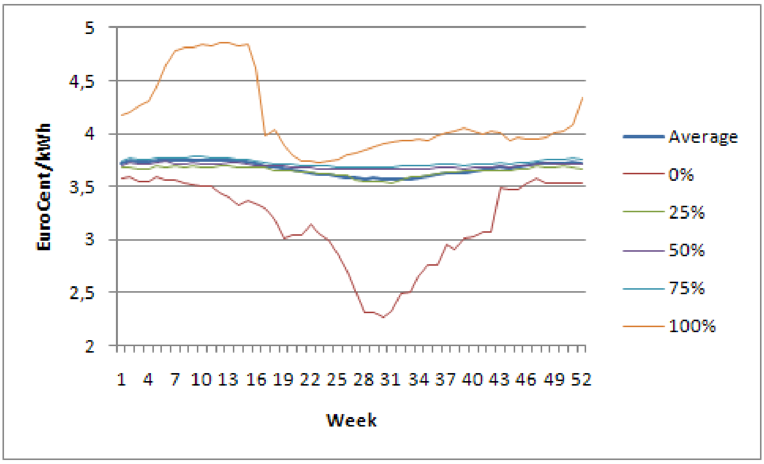

Figure 6.6: Prices in the Netherlands with a transmission capacity investment of 3400 MW

36-37 $\frac{EuroCent}{kWh}$, see figure 5.3, the price have now dropped to less than 5 $\frac{EuroCent}{kWh}$.

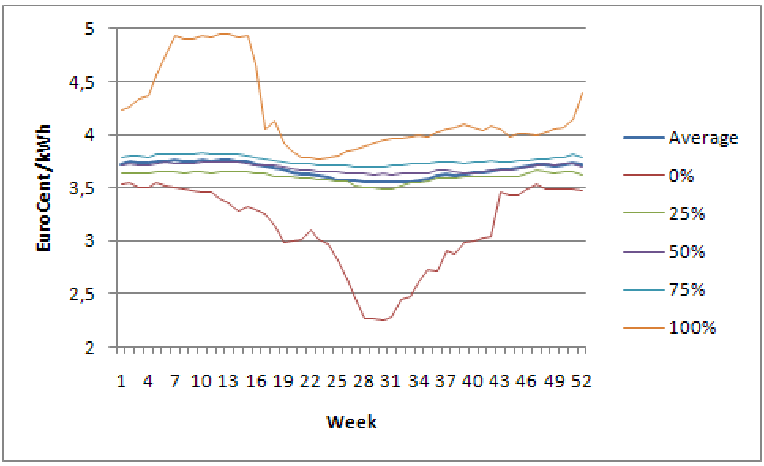

Figure 6.7: Prices in "Sørlandet" with a transmission capacity investment of 3600 MW

Another reason for why no further investment is carried out could be

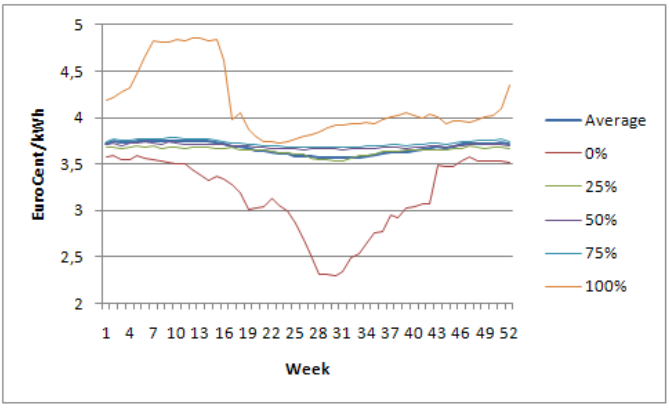

Figure 6.8: Prices in the Netherlands with a transmission capacity investment of 3600 MW

that the capacity from "Sørlandet" to the other areas in Norway is reaching its limit. To test this out the three lines connecting "Sørlandet" to "Sør-Øst" Telemark and "West-South" were added as possible investment alternatives. One problem here is to determine the investment costs for these lines. The license applications from Statnett [13] only include voltage upgrades. These investments are however added as new lines with increased capacity. The annual investment price was therefore simply set to be the same as another transmission capacity increase project that Statnett has, Nea-Järpströmmen. The price of this line is 75000000 €, the capacity 200MW and the lifespan 25 years. [16] [9] [17]. The resulting annual investment cost for these lines was 2529 $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$. The result of this simulation are shown in figure 6.9

There are significant investments in the lines between "Sørlandet" and "South-West" and "Sørlandet" and "West-South". The investment in these lines do however not influence the line between the Netherlands and "Sørlandet" as it still stays at 3400 MW.

It turned out that the reason why the profit suddenly dropped to 0 at 3600 MW was that the price dependant contracts specified for the Netherlands had a maximum energy imported/exported at 122.6400 $\frac{GWh}{week}$. Af-

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Runde: 38(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)    Avanse:   6972.9    Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)    Avanse:   8165.4    Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)    Avanse:   8829.9    Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:   8059.8    Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:   9125.7    Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:  15375.6    Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND      Ekstra:    3400 (MW)    Avanse:  19948.9    Inv.kost.  :  4280
( 3) SORLAND   - SOROST         Ekstra:     900 (MW)    Avanse:   3197.6    Inv.kost.  :  2529
( 4) SORLAND   - TELEMARK       Ekstra:       0 (MW)    Avanse:   1489.6    Inv.kost.  :  2529
( 5) VESTSYD   - SORLAND        Ekstra:     300 (MW)    Avanse:   2725.0    Inv.kost.  :  2529
```

Figure 6.9: Results of investment analysis with additional transmission grid investment alternatives

ter investing in more than 3400 MW this limit was reached and the profit dropped to zero. This illustrates the importance of specifying the input data correctly before running simulations.

After correcting the amount to a value so high that it would not run out of power to either import or export a new investment analysis was carried out. The final result is shown in figure 6.10.

```
Runde: 16(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)    Avanse:   8996.8    Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)    Avanse:  10237.5    Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)    Avanse:  10743.9    Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:   8431.7    Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:   9552.2    Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)    Avanse:  16173.2    Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND      Ekstra:    6000 (MW)    Avanse:   7388.7    Inv.kost.  :  4280
```

Figure 6.10: Final Iteration, increased import/export contracts

The maximum invested capacity was now 6000 MW. This is because the lines out from "Sørlandet" cannot support any more. The total capacity of the four transmission lines connected to "Sørlandet" is 4300 MW. Fixed demand in "Sørlandet" is 1500 MW and elastic demand accounts for 200 MW.

A comparison of the prices does now show that they are very close to being the same, which is also reflected in the profit from the last iteration.

The prices can be seen in the figures 6.11 and 6.12.

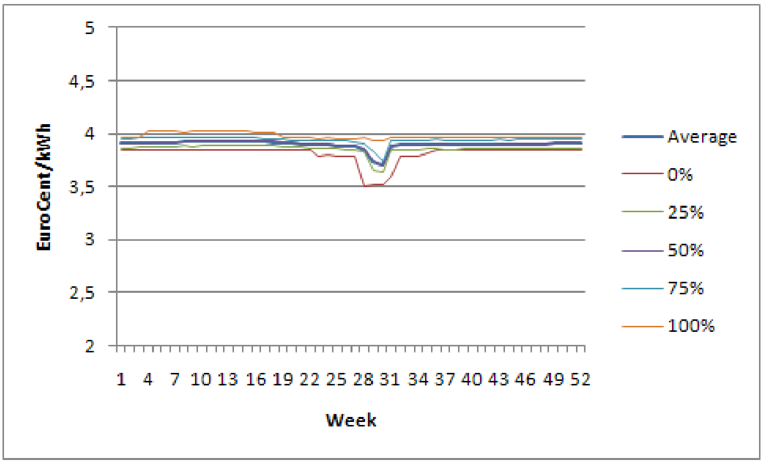


Figure 6.11: Prices in "Sørlandet" with a transmission capacity investment of 6000 MW

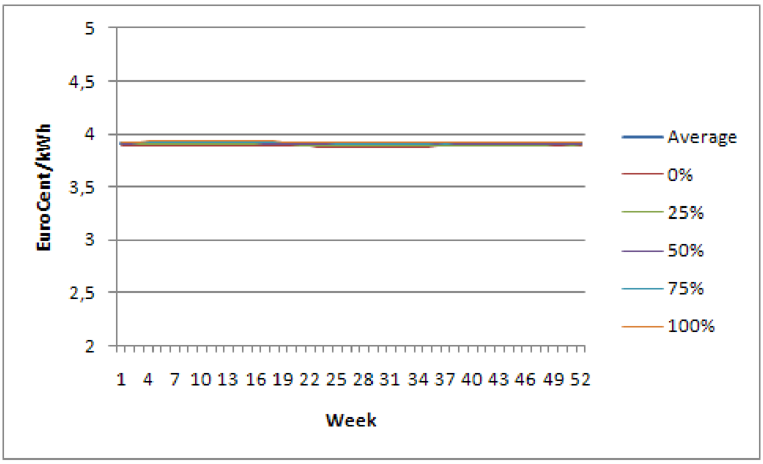


Figure 6.12: Prices in the Netherlands with a transmission capacity investment of 6000 MW

Investing in 6000 MW of cable capacity to the Netherlands would however probably be unrealistic. Adding a cable with the size of 6000 MW would influence the prices significantly on the Dutch side as well, not only on the Norwegian side. Importing 6000 MW from Norway would also require transmission grid updates in the Netherlands. The cost of strengthening the Dutch grid is not considered in this investment analysis.

The impact the additional capacity the NorNed cable has gained can be seen in figures 6.13 and 6.14. It shows the prices in all areas in the model using the average of all inflow scenarios and weekly prices.

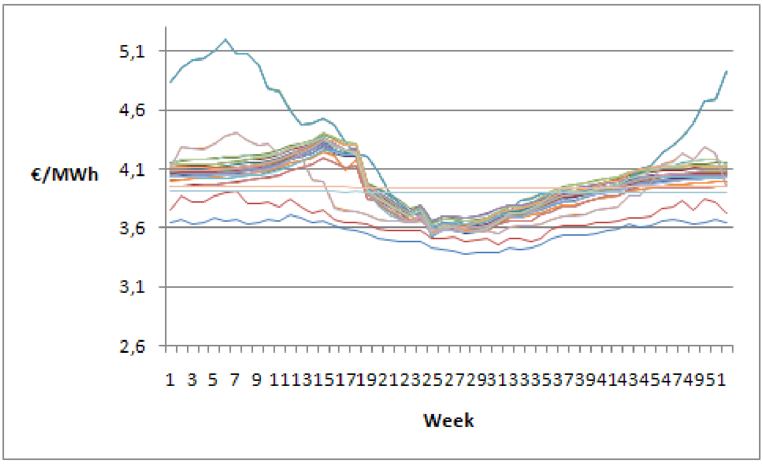


Figure 6.13: Prices in all areas in the model before investing

The prices after investing in an additional capacity has resulted in slightly higher prices on average in the Nordic system. Three areas do however separate themselves from the rest in figure 6.13 and 6.14. The three areas are Finland, Wind Finland South and Wind Finland North. (The three areas are connected with infinite capacity and therefore the prices are exactly the same, and can only be seen as one line in the plot). These three areas have a significant higher electricity cost during the winter, peaking at above 5.1 EuroCent/kWh.

One of the main reason for investing in cables to other power systems is to use the difference in prices in the different price segments. The Netherlands have lower prices during the night time and higher prices during the high

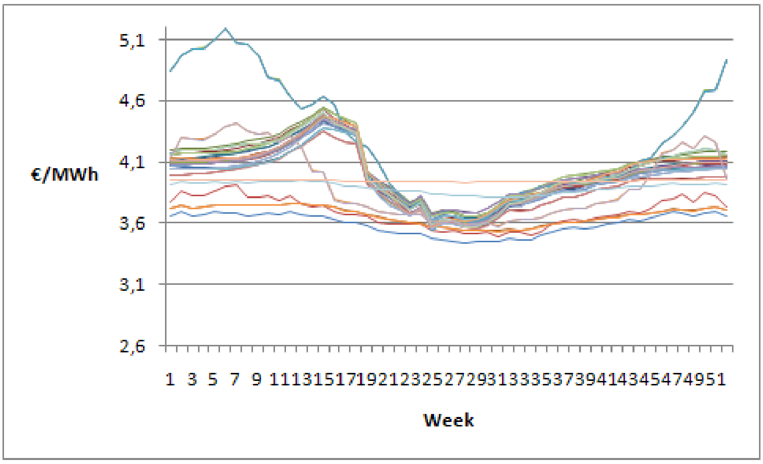


Figure 6.14: Prices in all areas in the model after investing

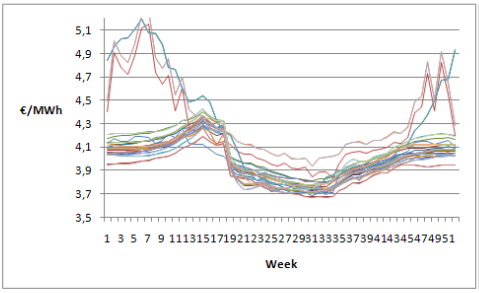
load situations during the day and the difference in prices before and after should be easy in these price segments. This should give a clearer picture as to why the prices go up than figure 6.14. A comparison of the price segments 1 (High Day), 3 (Base) and 4 (Night) can be seen in figure 6.15 and it can be seen that in the price segments 1 and 3 an increase in prices happens after investing in more transmission capacity to the Netherlands. In price segment 4 the opposite happens, with the prices dropping.

6.3 New price dependent contracts

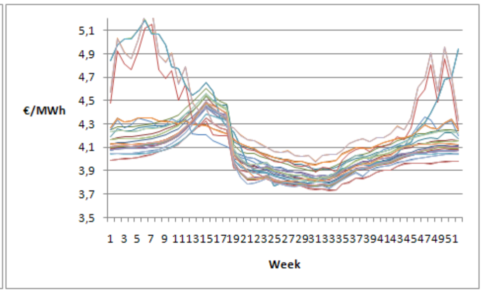
The prices used in the price dependent contracts have, as previously discussed in 5.4.3, great influence on the flow in the NorNed cable. It should therefore also influence the investment analysis. The simulations where therefore run for four different scenarios. 5% and 10% increase and reduction of the price dependent contracts. Everything else was left as it was and no other transmission lines were entered as investment alternatives.

The results of the simulations can be seen in table 6.2

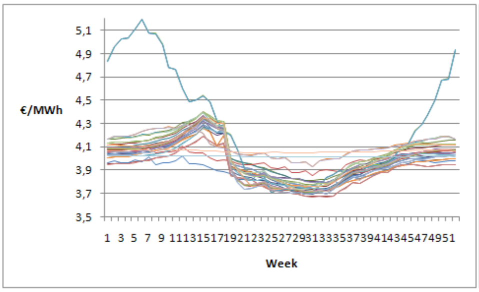
Due to the limitation in the transmission grid from "Sørlandet" to the



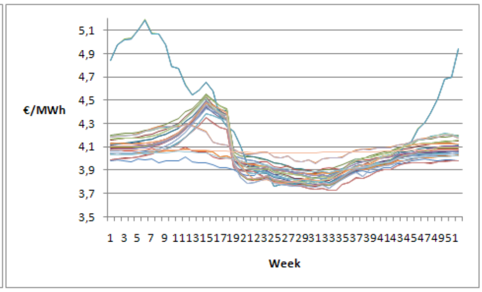
(a) Price segment 1, before



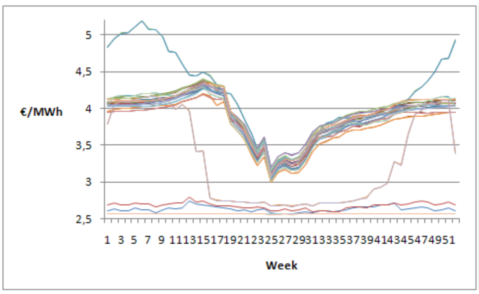
(b) Price segment 1, after



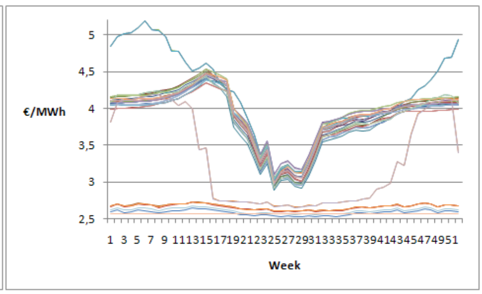
(c) Price segment 3, before



(d) Price segment 3, after



(e) Price segment 4, before



(f) Price segment 4, after

Figure 6.15: Prices in all areas in different price segments, before and after investing in capacity to the Netherlands

other parts of Norway the maximum invested capacity did not change. Investing in 6000 MW of transmission capacity will in any case be unrealistic. By setting the max capacity to 1200 MW (one of the alternatives Statnett explored) it is possible to instead look at the profit of adding one further

Table 6.2: Results of the investment analysis with different price dependent contracts

Change	Result
5% increase	6000 MW
10% increase	6000 MW
5% decrease	6000 MW
10% decrease	6000 MW

MW of capacity and see what kind of an effect the changed price dependant contracts have on this value. Table 6.3 shows the results from the different scenarios.

Table 6.3: Results of the investment analysis with different price dependent contracts

Contract	Profit	Change
original contract	38787.4	
5% increase	45733.8	17.9%
10% increase	53988.4	39.2%
5% decrease	39950.6	3%
10% decrease	41404.4	6.7%

Profits have increased significantly when increasing the prices of the price dependant contracts. An increase of 10% has resulted in an increase of 39.2% A profit of 53988.4 $\frac{EuroCent}{kW \cdot year}$ means that the investment will be paid back in less than 2 years, compared to a little less than 3 years for the original simulation. Decreasing the prices of the contracts also resulted in increases in the profit, but much smaller than when increasing them. This proves the point that modeling the Netherlands (and Germany) correctly is very important to get realistic results.

6.4 Consequences of wind power

Investing in wind power along the coast of South Norway might is something that might happen in the future. Wind power has very high investment costs but the operating and maintenance costs are very small. This means that wind power plants want to produce as much as they can whenever the wind is blowing. To achieve that they will bid into the Nordpool with very low prices. This means that during the day and, most notably, during the night another source of very cheap power will be available alongside the NorNed cable. This section aims to see if adding wind power will have an effect on the flow to/from the Netherlands. This analysis does not consider whether or not investing in wind power in the respective areas will be profitable. The full results of the simulations can be seen in Appendix

Table 6.4 shows the wind power farms inserted into the Nordic system by their size and location.

Table 6.4: Wind power farms inserted into the system

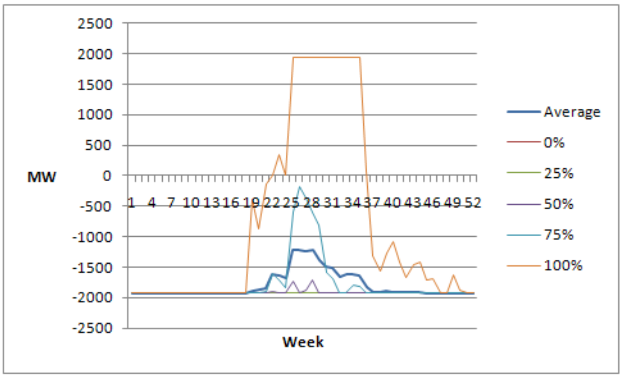
Area	**Size**
24, Vestmidt	400 MW
25, Vestsyd	400 MW
26, Norgemidt	400 MW

An investment analysis was run with the line between "Sørlandet" and the Netherlands as the only investment alternative. The max capacity of this line was again set to 1200 MW, as investing in a higher capacity seems unlikely at this time. The result of the investment analysis is shown in fig 6.16.

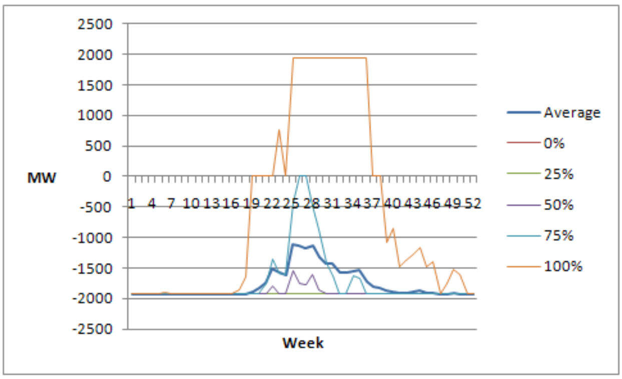
```
Vindkraft:
(24) VIND_SORLA  Modulnr.: 500 Kapasitet:  400 (MW)   Avanse:  14625.8   Inv.kost.:       1.
(25) VIND_VESTS  Modulnr.: 500 Kapasitet:  400 (MW)   Avanse:   9031.0   Inv.kost.:       1.
(26) VIND_VESTM  Modulnr.: 500 Kapasitet:  400 (MW)   Avanse:   7689.1   Inv.kost.:       1.

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:   1200 (MW)   Avanse:  36712.1   Inv.kost.  :  4280
```

Figure 6.16: Results with added wind farms

The profit is 36712,1 $\frac{EuroCent}{kW \cdot year}$ a change of 5.4% compared to before when no wind power investments were done. Continuous production of cheap power should theoretically lower the imports needed from the Netherlands during the night and increase the amount exported to the Netherlands during the day. Figure 6.17 shows a comparison of the prices with and without added wind power.



(a) No wind



(b) With wind

Figure 6.17: Flow on NorNed during the night, with and without wind power farms

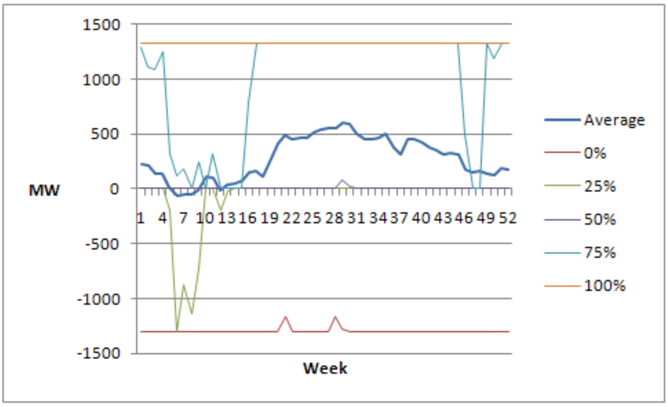
The results clearly show that the export to the Netherlands has decreased by a small amount. The 100% percentile has the biggest change, but also the 75% and 50% percentiles have reduced export during the summer. The addition of wind power does not influence the NorNed cable during the winter period.

As mentioned previously the exact opposite is expected to happen during the base load price segment. Figure 6.18 shows the flow in the NorNed cable in this case.

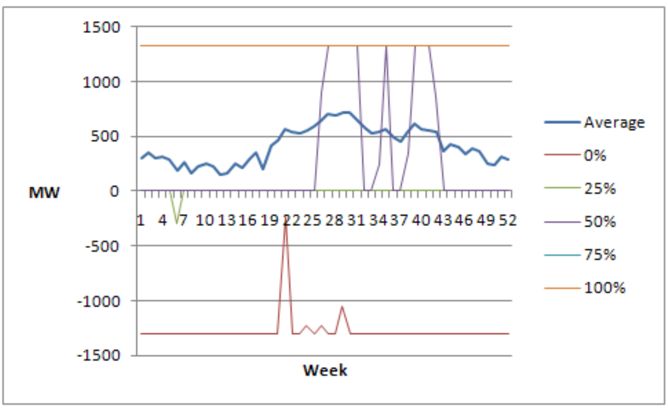
The flow on the line has indeed changed as suspected for all but the 100% percentile.

A possible scenario for the future might be that Norway is used as "green" power for Central Europe. The most plausible way to achieve that is to invest heavily in wind power in Norway. As the previous investment analysis showed the profit dropped when adding some wind power to the southern parts of Norway. If this amount of installed wind power is increased to 4500 MW (1500 MW in each of the three areas) then there should be a significant drop in profits, due to a drop of imported power during the night. The result of the simulation can be seen in 6.19.

Profit of adding one extra MW of capacity to the Netherlands has now dropped to 31702.4 $\frac{EuroCent}{kW \cdot year}$, a drop of 18.3% from when no wind power was installed in these areas. The flow on the NorNed cable during the night, figure 6.20, has now changed significantly from the original scenario without 4500 MW of extra wind power installed. The amount of imported power during the night from the Netherlands has decreased.



(a) No wind



(b) With wind

Figure 6.18: Flow on NorNed during base load, with and without wind power farms

```
Runde:  3(A)

Termisk kapasitet:
( 2) OSTLAND      Typenr.: 13   Kapasitet:    0 (MW)   Avanse:    5555.0   Inv.kost.:  320000.
( 7) VESTSYD      Typenr.: 13   Kapasitet:    0 (MW)   Avanse:    6551.6   Inv.kost.:  320000.
( 9) NORGEMIDT    Typenr.: 13   Kapasitet:    0 (MW)   Avanse:    7584.7   Inv.kost.:  320000.

Vindkraft:
(24) VIND_SORLA  Modulnr.: 500 Kapasitet: 1500 (MW)   Avanse:    9499.4   Inv.kost.:       1.
(25) VIND_VESTS  Modulnr.: 500 Kapasitet: 1500 (MW)   Avanse:    9964.2   Inv.kost.:       1.
(26) VIND_VESTM  Modulnr.: 500 Kapasitet: 1500 (MW)   Avanse:   10607.0   Inv.kost.:       1.

Transmisjonslinjer:
(46) SORLAND    - NEDERLAND      Ekstra:   1200 (MW)   Avanse:  31702.4   Inv.kost.  :  4280
```

Figure 6.19: Results with alot of added wind farms

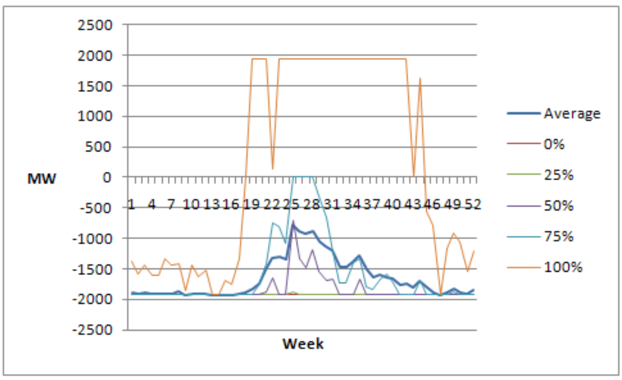


Figure 6.20: Flow on NorNed during the night, with and without wind power farms

Chapter 7

Discussion

7.1 Input data

The contracts used to model the Netherlands and Germany did ensure that the flow of the line would somewhat resemble what happens in real time. The flow during the night did mainly go from the Netherlands towards Norway and in the opposite direction during the peak hours of the week. There was also reasonable seasonal variations in the flow meaning that during the winter there is more export to Norway, which coincides with the reservoirs in Norway emptying leading to higher prices, and more flow towards the Netherlands during the summer when the reservoirs in Norway are filling up with water.

Results from the sensitivity analysis of the price dependant contracts, used to model Germany and the Netherlands, showed that a small change in the prices would result in a changed flow on the NorNed cable. Increases in the prices used in the contracts resulted in more flow towards the Nordic system, whereas a decrease in prices had the opposite impact on the NorNed cable. This was could also be seen in the profit calculations using the investment analysis program where a 10% increase in prices resulted in a profit change of 39.2% because the profit of selling to the Netherlands during the day drastically increased. This means that the results of the investment analysis should be questioned.

When assigning the price dependent contracts to the different price segments only three different sets of contracts where used. E.g the base load contract set (one for import and one for export) was assigned to three different segments: high evening, low day and weekend. Assigning different contracts for each of the different price segments and also adding more than one for import and one for export with a stepwise increase in the amount bought/sold at different prices would give a better representation of the flow.

The license application for the NorNed cable [14] states that the prices in the Netherlands are significantly higher than in Germany. Based on the future power derivative markets for Germany and the Netherlands however the prices were found to be fairly similar with Germany actually having slightly higher prices. The price dependant contracts used in this is report are based on the values from the future power derivative markets. Using much higher prices in the Netherlands would influence the flow on the NorNed cable and the connections to Germany.

When modeling a country only by using price dependent contracts the internal dynamics of the country is ignored. The price dependent contracts do for example not change as a function of the imported power. A great import of power would lead to the prices in the area dropping and thereby reducing the price at which the country starts importing. There is also no information given on the transmission grid in the Netherlands or Germany. There might e.g. be costs associated with strengthening the grid when doing investments in cross border cables that is not included in the investment costs used in the simulations. This means that the calculated profit, and also the invested capacity, in the investment analysis probably is higher than it should have been.

7.2 Simulations

Before any simulations were carried out a calibration of the model was completed. The aim of the calibration is to ensure that the reservoirs in the model are used correctly. This means that during periods with inflow into the reservoir there should be enough free capacity to make sure that no water is being spilled, or at least as little as possible. In seasons when there is no inflow to the reservoirs they have to make sure that they do not run out of water, leading to rationing something which is very expensive.

The problem here is that this calibration is only run before any change is done to the system, e.g. when the investment analysis program invests in additional capacity to the Netherlands. Ideally you would want to run a calibration between each iteration. Calibration is however very time consuming, and if a calibration is run for each iteration an investment study could take two or three weeks assuming that 15-20 iterations are needed. And that is without taking into account reservoir drawdown which would mean a lot more time consumed! One solution to this could have been to run one calibration before doing any investments and then do a calibration after. There was unfortunately no time for that in this study.

All the simulations with different variations of the price dependent costs did show that an investment in additional capacity to the Netherlands is profitable up to as much as 6000 MW. The reason why it capped out at 6000 MW was that the three connection "Sørlandet" has to other parts of Norway alongside the demand within amounted for a total of 6000 MW. Investing in additional transmission capacity would naturally further increase the maximum profitable capacity between Norway and the Netherlands. Figure 6.9 shows that the profit after investing in 3400 MW of between Norway and the Netherlands has increased when investing in the other transmission lines going to "Sørlandet" compared to when the NorNed cable was the only investment alternative.

Installing 6000 MW of cable in one go is unrealistic mainly because such a big connection between the countries would have such a significant impact on the prices in the Netherlands that are not taken into account in these simulations. An import of 6000 MW would also as previously mentioned seriously impact the way the reservoirs in Norway would be handled. This is however hard to model because the time consuming nature of recalibrating the model. Investing in a smaller capacity should however be considered even though it will result in overall higher prices for the consumers in Norway. The reason is that it will at the same time significantly reduce the prices in dry year scenarios in addition to being a highly profitable source of income for Statnett who could use the money to invest in strengthening of the Norwegian grid, or other projects. A cable in the region of 1200 MW would according to the simulations result in a profit of 38791.7 $\frac{EuroCent}{kW \cdot year}$. An investment that would pay itself within 3 years of installation.

The flow on the NorNed cable was also studied if investments in wind power farms were carried out in the southern parts of Norway. The results of these simulations showed that an investment in a medium amount of wind power (900 MW in total) would have an impact on the profits of the NorNed cable. Investing in 1200 MW of additional capacity alongside the wind power farms resulted in the profit of the NorNed cable to drop by 5.4%. When increasing the maximum capacity of the wind power farms even further to a total of 4500 MW the profit dropped by 18.3%. The reason why the profits dropped was that the line was used for less import to Norway during the night. This was due to the additional available cheap power from the wind power plants. This means that if Norway were to build wind power farms to supply Europe with "green" power the profits of the NorNed cable would drop per MW exported! Again it should be mentioned that a recalibration was not done. The result of recalibrating could be that the more of the power produced by the hydro power plants would be used for export during the day to ensure that spillage happens and thereby increasing the profit of the NorNed cable again.

7.3 Investment analysis program

The investment analysis program alongside the EMPS model seems to be a very handy tool when exploring different investment alternatives and studying the impact they have on the system. It allows the user to swap between different investment alternatives quickly and it allows the user to see how one investment impacts the profitability of another investment. It also greatly reduces the time used to simulate the different investment alternatives as the user is not forced to do all the changes manually in the EMPS model.

The investment analysis program is easy and quick to use. Running an invest analysis takes around 30-45 minutes depending on how many iterations are needed. If reservoir drawdown is used then this would increase quite a bit. If recalibration would be added to the simulation procedure the simulation time would increase significantly as previously mentioned. The time of running the investment analysis can however be reduced by using very large steps the first time around and then after finding a maximum run a new investment analysis with the maximum as the starting capacity and use a small jump to reach the optimal solution.

There are still a few small errors in the invest analysis program. The transmission line only iteration does only take into account the first transmission line investment alternative. If no investments for a a type (thermal, wind or transmission line) is specified the program fails. The investment costs have to be specified in $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$ as opposed to the more intuitive $\frac{€}{\text{MW}\cdot\text{Year}}$ and there should possibly be added a way to specify non-linear investment costs to improve the results. It could also be very interesting to add the possibility to account for the additional small scale hydro power that could be realised as a part of a transmission line. Finding realistic numbers for the possible profit of this could however prove to be very tricky.

Chapter 8

Conclusion

The modeling of Germany and the Netherlands using price dependant contracts did result in flows that resembled what is seen in the NorNed cable today. The flows during the night went towards Norway and during peak hours towards Germany and the Netherlands. Seasonal variances could also be seen in the cable.

The investment analysis resulted in an investment of 6000 MW in transmission capacity between Norway and the Netherlands. 6000 MW was the limit due to limitations in the grid from "Sørlandet" to the other parts of Norway. The way the Netherlands are modeled do however not take into account that the prices in the Netherlands also would change as a function of this capacity increase so it is fair to say that the resulting profits and thereby the invested capacity is too large. The investment analysis does show that an investment should be made as it is very profitable. An investment in the region of 1200 MW would result in the full investment costs being payed back within 3 years of installation according to the investment analysis.

Changing the prices used in the price dependant contracts did however have a big influence on the resulting flows, and thereby also the profit of increasing the transmission capacity between Norway and Central Europe. An increase in the prices used in the contracts of 10% would increase the profit of around 39.2%.

In the case where large amounts of wind power capacity was added to the southern parts of Norway a slight drop in the profit per MW of the NorNed cable could be noticed. This was due to the prices in Norway dropping during the night as a resulted of the added wind power that has very low O&M costs.

The investment functionality is a program that is quick and easy to use. It provides the user a way to specify alot of different investment alternatives. The program can be used to see the optimal investment in one or more investment alternatives and it also shows the impact they possibly have on each other. The program saves the user a lot of time as the user no longer has to manually add the investments into the EMPS model. There are however still a few errors that have to be fixed in the program and new features that could be added to improve the results, such as non-linear investment costs.

Chapter 9

Further Work

9.1 Improvements of the model

A better representation of the Dutch and the German markets have to be implemented to be able to properly calculate the optimal investment of capacity between Norway and the German and Dutch systems. The use of price dependant contracts to model the production and consumption results in that the prices in the Netherlands do not change as a function of the imported/exported as mentioned in chapter 6.2.2

9.2 Nordic model verification

In [3] errors in the modeling of the transmission capacity to Central Norway was found to be incorrect. There is therefore a possibility that there are more errors in the model, most notably in the transmission grid representation. Due to the high level of aggregation this can prove to be difficult, but reasonable numbers should be able to be found.

Also performing a thorough verification of the rest of the Nordic model should be done

9.3 Faults in the investment model

9.3.1 Transmission only iterations

As it is right now the investment model does not work properly in transmission capacity increase only iterations (Also called iteration 'B'). These iteration rounds are in the investment analysis to prevent rotation between different solutions. However only the first specified transmission investment is considered, the others are not. They are however considered in the analysis during the "normal" iterations (called 'A').

9.3.2 No investments

If the user is interested in e.g. only transmission grid investments the user would normally not specify any thermal power or wind power investments. Not doing this however leads to an error message from the program as it requires at least one of each investment to work properly. The solution to this is to specify thermal and wind investment alternatives with unrealistically high investment cost or with a maximum capacity set close to zero.

9.4 Changes that should be made to the investment model

9.4.1 Annual investment costs

In the investment model the annual investment costs are specified in $\frac{\text{EuroCent}}{\text{kW}\cdot\text{Year}}$. The program functions properly but it would probably be easier and more understandable for the user to use $\frac{€}{\text{MW}\cdot\text{Year}}$.

9.4.2 Non linear investment costs

All investment alternatives are in the investment model specified with linear investment costs. Every MW of additional capacity built has the same cost. For a transmission line the cost would however be lower per MW when building a transmission line with a large capacity compared to one with a small capacity. Adding annual investment costs in steps depending on how much is all ready built should be fairly easy to implement.

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Appendix A

Results of the sensitivity analysis

```
Runde:  4(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   7544.9   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8753.3   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   9333.7   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8154.8   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   9236.4   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15589.6   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:    1200 (MW)   Avanse:  45733.8   Inv.kost.  :  4280
```

Figure A.1: Results of simulation with a 5% increase of the price dependant contracts

```
Runde:  4(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   7845.7   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   9072.9   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   9588.6   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8211.7   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   9304.6   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15706.2   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:    1200 (MW)   Avanse:  53998.4   Inv.kost.  :  4280
```

Figure A.2: Results of simulation with a 10% increase of the price dependant contracts

```
Runde:  4(B)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   6956.3   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8049.9   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8946.3   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8045.5   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   9113.2   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15409.8   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:    1200 (MW)   Avanse:  39950.6   Inv.kost.  :  4280
```

Figure A.3: Results of simulation with a 5% decrease of the price dependant contracts

```
Runde:  5(A)

Termisk kapasitet:
( 2) OSTLAND     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   6379.9   Inv.kost.:  320000.
( 7) VESTSYD     Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   7365.3   Inv.kost.:  320000.
( 9) NORGEMIDT   Typenr.: 13   Kapasitet:    0 (MW)   Avanse:   8443.7   Inv.kost.:  320000.

Vindkraft:
(27) VIND_NORMI  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   7929.6   Inv.kost.:  601500.   (Linjer:  1)
(28) VIND_HELGE  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:   8980.8   Inv.kost.:  601500.   (Linjer:  1)
(30) VIND_FINNM  Modulnr.: 500 Kapasitet:    1 (MW)   Avanse:  15194.1   Inv.kost.:  604500.   (Linjer:  3)

Transmisjonslinjer:
(46) SORLAND   - NEDERLAND     Ekstra:    1200 (MW)   Avanse:  41404.4   Inv.kost.  :  4280
```

Figure A.4: Results of simulation with a 10% decrease of the price dependant contracts

Appendix B

Areas and transmission lines in the Nordic model

Table B.1: List of areas

Area #	Area name	Country
1	Glomma	Norway
2	East Norway	Norway
3	South East Norway	Norway
4	Hallingdal	Norway
5	Telemark	Norway
6	South Norway	Norway
7	South West Norway	Norway
8	West Norway	Norway
9	Central Norway	Norway
10	Helgeland	Norway
11	Troms	Norway
12	Finnmark	Norway
13	Upper North Sweden 1	Sweden
14	Upper North Sweden 2	Sweden
15	North Sweden 1	Sweden

Continued on Next Page…

Table B.1 – Continued

Area #	**Area name**	**Country**
16	North Sweden 2	Sweden
17	Central Sweden	Sweden
18	South Sweden	Sweden
19	West Denmark	Denmark
20	East Denmark	Denmark
21	Finland	Finland
22	Wind North Finland	Finland
23	Wind South Finland	Finland
24	Wind South Norway	Norway
25	Wind South West Norway	Norway
26	Wind West Norway	Norway
27	Wind Central Norway	Norway
28	Wind Helgeland	Norway
29	Wind Troms	Norway
30	Wind Finnmark	Norway
31	Wind Upper North Sweden	Sweden
32	Wind North Sweden	Sweden
33	Wind Central Sweden	Sweden
34	Wind South Sweden	Sweden

Table B.2: Transmission lines in the model

Line nr.	**From**	**To**
1	Sorost	Ostland
2	Telemark	Sorost
3	Sorland	Sorost
4	Sorland	Telemark
5	Vestsyd	Sorland
6	Vestsyd	Telemark
7	Vestsyd	Vestmidt

Continued on Next Page…

Table B.2 – Continued

Line nr.	From	To
8	Vestmidt	Hallingdal
9	Vestsyd	Ostland
10	Vestsyd	Sorost
11	Hallingdal	Ostland
12	Norgemidt	Ostland
13	Helgeland	Norgemidt
14	Troms	Helgeland
15	Finnmark	Troms
16	Glomma	Ostland
17	Ostland	Sver-midt
18	Norgemidt	Sver-nn2
19	Helgeland	Sver-nn2
20	Troms	Sver-on2
21	Finnmark	Finland
22	Sver-on2	Finland
23	Sver-midt	Finland
24	Sorland	Danm-vest
25	Sver-midt	Danm-vest
26	Sver-syd	Danm-ost
27	Sver-nn2	Sver-midt
28	Danm-ost	Danm-vest
29	Sver-on1	Sver-on2
30	Sver-on2	Sver-nn1
31	Sver-nn1	Sver-nn2
32	Sver-midt	Sver-syd
33	Finland	Vind_fino
34	Finland	Vind_fisy
35	Sorland	Vind_sorla
36	Vestsyd	Vind_vestsy

Continued on Next Page...

Table B.2 – Continued

Line nr.	**From**	**To**
37	Vestmidt	Vind_vestmi
38	Norgemidt	Vind_normi
39	Helgeland	Vind_helge
40	Troms	Vind_troms
41	Finnmark	Vind_finnm
42	Sver-on1	Vind_sveon
43	Sver-nn2	Vind_svenn
44	Sver-midt	Vind_svemi
45	Sver-syd	Vind_sveso

Appendix C

Wind utilization

Table C.1: Wind utilization, Sogn og fjordane

Location	**Capacity, MW**	**GWh per year**
Ytre Sula	7.5	22
Setenesfjellet	50	145
Okla	21	65
Guleslettene	180	490
Brosviksåta	90	225
Vågsvåg	24	63
Kyrkjestein	41	107
Hennøy	35	64
Bremangerlandet	110	355
Guleslettene	200	640
Ytre Sula	150	450
Uøvegreina	140	400
Total	87.38	252.17
Utilization	2.89	

Table C.2: Wind utilization, Rogaland

Location	**Capacity, MW**	**GWh per year**
Karmøy	75	210
Helleheia	60	165
Tellenes	156	470
Svåheia	24	65
Faurefjellet	60	181
Gilja	240	405
Egersund	110	305
Njåfjell	10	35
Stokkafjellet	80	225
Sandnes	100	300
Fruknuten	90	270
Skakksiå	90	250
Holmafjellet	66	190
Risavika	24	68
Total	98.75	261.58
Utilization	2.65	