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Analyses of Reserve Procurement Costs Using the EMPS Model

Case Study Norway 2050

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Preface

This master thesis is written at the Department of Electric Power Engineering at the Norwegian University of Science and Technology, NTNU. The master thesis was written during the spring semester of 2017 and is the delivery of the course *TET4900: Electric Power Engineering and Smart Grids, Master Thesis.* A specialization project was carried out as a preliminary study for this master thesis, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1], during the fall 2016. The work of the specialization and master project is carried out in cooperation with researchers at SINTEF Energy.

My supervisors have provided me with a high degree of freedom when deciding the objective, scope and work packages of my project. I feel confident to say that throughout the work with the master project I have not only become more knowledgeable in the theoretical and practical knowledge in modelling and analysing the power system, but also become more independent in my work and decision taking.

I feel privileged to be able to study and contribute to finding better energy solutions for the future. In relation to current political events it is important to stress the awareness of the impacts of the climate changes and the press of time if we are going to succeed with providing a liveable planet to the future generations.

I want to honour my supervisors, Hossein and Arild, for patience and support throughout the master project work. Hossein has been a constant motivation, with enthusiasm and positivity for my project, and Arild have provided me with expert knowledge about the EMPS model. I want to thank Ingeborg Graabak and Stefan Jahnert at SINTEF Energy and my collage at NTNU, Audun Tysnes, for help with building the data set and insights in the EMPS model. I also want to thank my colleagues at Energy and Environmental Engineering for a great master year, and finally, my friends and family for endless support throughout my five years at NTNU.

Trondheim, 2017-06-16
Tale Marie Astad Paulshus

Summary

Europe is moving towards an energy transition including increasing the share of power produced from renewable energy sources and an increase of the CO2 price in order to reduce the climate changes and curtail the damaged caused by emissions. A shift towards a larger share of power generation from renewable sources results in greater variations in power outputs and thus a greater need for reserve power to balance the power system. The Norwegian hydro power holds characteristics that make it fit to provide reserve power and is the motivation for the master project. The goal of the master project is to quantify and perform sensitivity analysis on reserve procurement costs in a simplified model of the Norwegian power system using the EMPS model as a modelling- and simulation tool for scenarios representing Norway and Europe in 2050. The EMPS model simulates the power market and handles hydro power in a detailed matter, including water value calculations to determine the value of water in reservoirs.

The master thesis is divided into three subsections: The first section present the theory, including modelling and solution principles, optimization problems, cost of reserves, setting reserve requirements, the project used to extract data for the scenarios, the e-Highway2050 project, and a presentation of the EMPS model.

The second subsections review the process of developing the scenarios by presenting the initial data set, the assumptions, the implementation process and the modified data sets, the scenarios.

The analysis takes part in the third subsection. The analysis is assembled by two cases, Case I and Case II. Case I has the objective to quantify the theoretical reserve requirements for the scenarios and to quantify the cost of introducing the reserve requirements in the three scenarios by the dual value of the reserve restriction included in the optimization problem, the difference in socioeconomic surplus and the effect on the power prices. The simulations showed that Norway has a large surplus of power and hence low prices of power in all of the scenarios. Introducing the reserve requirements in the data sets had a price and a cost, represented by the values listed, for all scenarios, but differs in extent. Case II has the objective to perform sensitivity analysis on the scenarios by investigating the trends of reserve prices (dual values), total socioeconomic surplus and power prices when increasing the reserve requirements with 2, 3,4 and 10 of the theoretical reserve requirements calculated in Case I to be able to handle dimension fault in the Norwegian power system. The findings in all of the scenarios coincided: The reserve prices increases with increasing reserve requirements, the difference in socioeconomic surplus increased with increased reserve requirements, the power prices in the time periods with initially high power prices were increased and the time period with prices near zero decreased with increasing reserve requirements.

Sammendrag

Klimaforandringene er en trussel for fremtiden, og for å bremse og redusere skadene av utslipp går Europa mot et skifte i energiproduksjon; mot kraftproduksjon fra fornybare energikilder og økning av CO2-prisen. Et skifte mot en større andel kraftproduksjon fra fornybare energikilder medfører større variasjoner i kraftproduksjoner og dermed et større behov for reservekraft til å balansere kraftsystemet. Den norske vannkraften innehar karakteristikker som gjør at den kan brukes som reservekraft, og er motivasjonen for masterprosjektet. Masterprosjektet har som mål å kvantifisere og utføre sensitivitetsanalyse på kostnader for reservekraft i en forenklet modell av det norske kraftsystemet med Samkjøringsmodellen som modellerings- og simuleringsverktøy for scenarioer (med økt vind- og solkraft) i 2050. Samkjøringsmodellen simulerer kraftmarkedet og behandler vannkraft detaljert, blant annet ved vannverdiberegninger for å bestemme verdien av vann i reservoarer.

Masteroppgaven kan deles inn i tre hoveddeler. I den første delen forklares teorien som senere blir benyttet. Teoridelen tar for seg modelleringsprinsipper, en detaljert gjennomgang av oppsett for optimaliseringsproblemer, reservekostnader, hvordan sette krav til reserver, e-Highway prosjektet som er benyttet for data til scenarioene og en gjennomgang av Samkjøringsmodellen.

Den andre delen av oppgaven tar for seg datasettene. Gjennom å presentere det initielle datasettet, bruk av data fra e-Highway prosjektet, antagelser, implementering og presentasjon av de modifiserte datasettene, scenarioene, ønsker forfatteren å få frem prosessen med utviklingen av scenarioene.

Den tredje delen av oppgaven inneholder analysen. Analysen er satt sammen av to caser, Case I og Case II. Case I har som mål å kvantifisere de teoretiske reservekravene i de tre scenarioene og kostnadene innføringen av reservekravene medfører i form av reservepriser, samfunnsøkonomisk overskudd og påvirkning i kraftprisene. Det ble funnet at Norge har et stort overskudd av kraft i alle scenarioene og at kraftprisene dermed er lave i Norge. Det ble likevel funnet at innføringen av reservekravene medførte en kostnad for systemet i form av de nevnte verdier. Case II har som mål å utføre sensitivitetsanalyse og utforske trendene i reservepriser, samfunnsøkonomisk overskudd og påvirkningen i kraftprisene når reservekravet blir økt med 2, 3, 4 og 10 ganger verdien av det teoretiske reservekravet funnet i Case I, for å kunne takle dimensjonerende feil i det norske kraftsystemet. I alle scenarioene økte reserveprisene med økt reservekrav, det samfunnsøkonomiske overskuddet hadde økende endringer ved økende reservekrav, kraftprisene ble betraktelig økt i perioden med allerede høye kraftpriser og tidsperioden med kraftpriser nær null ble kortet ned med økende reservekrav.

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Abbreviations and definitions

4del	The EMPS data set used in the master project
BRP	Balance Responsible Party
BSP	Balance Service Provider
CCS	Carbon Capture Storage
DAM	Day-ahead Market
DSO	Distribution System Operator
e-Highway2050	The e-Highway2050 project
EMPS	EFI's Multi-area Power-market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
GDP	Gross Domestic Product
HPP	Hydro Power Production
IDM	Intraday Market
NPS	Nordic Power System (here: synchronous)
R0	Theoretical reserve requirement relative to scenario
RES	Renewable Energy Sources
RPP	Renewable Power Production
SPP	Solar Power Production
SS	Socioeconomic Surplus
TSO	Transmission System Operator
WPP	Wind Power Production

1 Introduction

1.1 The master project

Problem definition and motivation

The climate changes are more relevant than ever. In order to slow down and lower the consequences of the climate changes, it is necessary to cut emissions in all sectors, including the power sector. A possible solution is an energy transition towards renewable energy, such as sun and wind, and away from traditional power plants, such as coal and gas. Another one is the increase of the CO2 price. If the CO2 price increases, the order of prices for production changes from the present order; the CO2 price can be increased to a level where coal becomes a less attractive fuel than gas. An energy transition and/or increase in the CO2 price will have consequences in Norway; it may be relevant to build more renewable production, e.g. production of power from water, wind and sun. A more interconnected Europe is also expected.

A way of preparing for possible scenarios for the future is to simulate the power system with values adapted to future scenarios. Norway has a long tradition of simulating the power system to plan production and to simulate extensions of the system. Similarly, one can simulate a power system similar to what we have today, but with other types of and values for production, load and interconnections for transmission. By simulating, information about possible future scenarios can be gathered and an information basis for decision takers can be built up. The results from simulations of one scenario can be compared with the current power system and/or with other scenarios to discover challenges and solutions for a possible future.

Norway has a large share of regulative power; power generated from water in hydro reservoirs. The owner of these plants has the freedom to decide when and how they want to use the water and produce power. Their only restrictions are regulations from the government, inflow of water and the size of the reservoir. If Europe and Norway follow the energy transitions towards an increased amount, and share, of wind and solar power, which are not possible to regulate but are dependent on the weather, an increased need for reserve power will follow. The reserve power must be available at all times and fed into the system once the wind speed decreases or clouds cover the sun. In these future scenarios, the value of the Norwegian hydro power can increase because it holds the characteristics that are required of reserve power. This is highly relevant and the motivation for the master project: Prices for reserve power for scenarios representing possible versions of 2050 will be presented and discussed.

Research question

The goal of the master project is to quantify and perform sensitivity analysis investigating reserve procurement costs in a simplified model of the Norwegian power system using the EMPS model as a modelling- and simulation tool for scenarios representing Norway in 2050.

Divided into objectives, the three objectives are:

1. With basis in a default SINTEF data set, develop three data sets to represent three scenarios of Norway 2050.
2. Quantify the cost and value of reserves.
3. Perform sensitivity analysis and conclude with trends in the costs when adjusting the reserve requirements.

Objective 2. and 3. are to be performed by running the simulations on the data sets representing the scenarios in 2050, the use of the reserve application and applications for processing of results in the EMPS model.

Scope

The master project contains building a data set and simulating scenarios for the Norwegian power system in 2050, using the EMPS model as tool. Results are to be extracted and analysed and sensitivity analysis performed. A default data set obtained from SINTEF Energy is used as the starting point for the new data set in which later are used to form the scenarios. The initial data set has been extended by including new types of generation and energy series for wind and solar power production.

The Norwegian power system is modelled in a simplified way to suit the project objectives: Three nodes describe Norway and are linked to the rest of Europe, which is described by a fourth node. The EMPS model is known to have a detailed description of the waterways and hydro power systems, which is important in a hydro-dominated country like Norway. This functionality is included in the Norwegian nodes. The transmission system is not in focus of the project, and is modelled in a simplified way. The physical structure used for the scenarios is simple, resulting in short calibration and run times, but with a detailed description of the hydro power systems. The uncertainty connected to renewable production is handled with calculation of water values for hydro and energy series for wind and solar power production. The model is adapted and suited for running multiple scenarios and being used to retrieve results and perform sensitivity analysis, which require relative fast calibration and run time. In the EMPS model, reserves are simplified to concern reserve capacity [MW] on a weekly basis during the year.

Contribution

- The default data set has been extended to include energy series from wind and solar power production, marginal cost and start-up costs for biomass, gas and coal (referred to as thermal generation).
- The data for the input values has been gathered from relevant sources, including the e-Highway2050 project, and processed the data by scaling it to fit with the framework in the default data set.
- Three data sets has been modified and calibrated in the EMPS model. The calibration process is a demanding process, which includes time consuming steps and adjustments.

The processes involving the data sets can be found in Part II: Data set, Chapter 4, 5 and 6.

- Reserve requirements has been calculated for the scenarios with basis in relevant theory.
- Cases have been developed and simulated on the data sets in the EMPS model.
- The output data from the simulations has been extracted, processed, presented, discussed and evaluated. The EMPS model produce large amounts of data in which had to be processed in Excel, by developing macros, before presented.

The result analysis can be found in Part III: Analysis, Chapter 7, 8 and 9.

1.2 Literature review

As a preliminary study for the master project, an evaluation of different energy system models [1] was executed. This was used as basis for the choice of using the EMPS model as modelling- and simulation tool in the master project.

To obtain information about how to decide the reserve requirement and how to find the price of the reserve procurements, a study of relevant literature was needed. Studies conducted at SINTEF and NTNU were used as starting point. Helseth et. al. [2] provides a review of the power market design and models used for hydro power scheduling, providing insights in the power markets and hence relevant theory for the master project. Helseth et. al. [3] and Fodstad et. al. [4] reviews the consequences of going from a energy-only market to joint trade of energy and reserve capacity market. I.e., the consequences of increasing the focus on reserves in the electricity market are studied, in which are relevant as the master project are evaluating the consequences of introducing reserve requirements in an electricity market. Wolfgang et. al. [5] investigates, using EMPS model, possible factors leading to the decrease in average levels of water in hydro reservoirs. The report contain a good introduction and description of the EMPS model, in which enlightened the author and provided ideas for the set-up of the thesis. Three PhD thesis, in which treat the integration of balancing markets and cross-boarder exchange of balancing services, Farahmand [6], Jahnert [7] and Gebrekiros [8], were used to provide theory and to find possible sources as input data for the scenarios. Sources as e.g. the e-Highway 2050 project [9]-[10] and the *World Energy Outlook* [11] by the International Energy Agency, were identified and used as input data basis for all scenarios, described in Section 2.5 and in Chapter 5. The numbers for dimensioning faults for Norway and how they are divided between the bidding zones, described in Chapter 9, are provided from Gebrekiros [8]. Holttinen et. al. [12] reviews reserves in power systems by the types of reserves, the impact of the reserves and how to calculate the reserve requirements. One of the methods for deciding the reserve requirements, *Statistical Approach Based on Sigma (Standard Deviation)*, are used in the master project to decide additional reserve requirements due to increased penetration of wind and solar power production. The method are described in detail in Section 2.4, where the theory for setting the reserves requirements are presented. Finaly, the SINTEF report Huse et. al. [13] are used to describe the start-up costs and the reserve requirements in the EMPS model in Section 3.3 and used for compartments of findings in the case studies conducted in the analysis, Part III.

Table 1.1: Overview, literature

Literature	Author(s)
Paulshus [1]	Present power market theory and evaluation of energy systems models.
Helseth et al. [2]	Reviews current power market designs in Norway and Sweden, focusing on the balancing markets, and provides a literature review of short- and long-term hydro power scheduling.
Helseth et. al. [3]	Optimal scheduling of hydro power when going from a energy-only market to a joint energy and reserve capacity market.
Fodstad et. al. [4]	Optimization of joint trade in the day-ahead and the balancing markets.
Wolfgang et. al. [5]	Investigating factors for decrease in average levels in reservoirs using the EMPS model.
Farahmand [6]	Investigate reductions in costs by integrating balancing markets in Northern Europe.
Jahnert [7]	Integration of national regulating power markets, enabling the cross-border exchange of balancing services in Northern Europe.
Gebrekiros [8]	Modeling integrated reserve procurement and balancing energy markets in a setting similar to the current sequential market clearance order in Europe.
Holttinen et. al. [12]	Review of reserves in a system with an increased share of wind power production.
Huse et. al. [13]	Reviews the implementation of the start-up costs and reserve requirements in the EMPS model and conducting tests after implementation.

1.3 Relation to specialization project

The author wrote a specialization project report during the fall of 2016, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1]. One of its deliveries was to provide the theoretical basis of this master project. Some material from the project report has been used in this master thesis in order to provide the reader with a solid theoretical basis and thus a better understanding of the master project.

Material from the specialization project has been used in the following sections:

- Section 2.1, completely reused
- Section 2.2, completely reused
- Appendix A, completely reused
- Appendix B, partly reused
- Appendix C, completely reused

1.4 Report structure

Chapter 1 introduces the overall problem, motivation, literature review and the scope of the master project.

The rest of the report is divided into three parts:

Part 1: Theory

Part 1 aim to provide all theory necessary for the reader to understand the master project and report. Chapter 2 includes optimization problems, how to calculate the reserve costs and the reserve requirements while Chapter 3 introduces the EMPS model and explains the input, simulation and optimization procedure of the model with text and figures.

Part 2: Data set

Part 2 aim to take the reader through the process of developing an implementing the scenarios. Chapter 4 present the initial data provided by SINTEF Energy. It is included to provide the author with a better understanding of the authors contribution in terms of modifications and development of the data set. Chapter 5 explains the usage of data taken from e-Highway2050 project and other sources, the processing of the data before the process of implementing and calibrating the scenario data are explained and the sources of errors and limitations are identified. Chapter 6 provides a summary of the input forming the scenarios and comparing the modified data sets with the original data set.

Part 3: Analysis

Part 3 includes the analysis. Chapter 7 describes the aim and objectives of the two cases to be executed in the analysis and the case set-up. Chapter 8 describes Case I, which includes the calculation of the theoretical reserve requirement for the scenarios, the results from the simulations before and after adding the reserve requirement to the scenarios and discussion of the findings. Chapter 9 describes Case II, which includes a sensitivity analysis of the impacts of increasing the reserve requirements by 2, 3, 4 and 10 times the theoretical requirement calculated in Case I. The concluding remarks obtained from the analysis are presented in Chapter 10 and the suggestions for further work are presented in Chapter 11.

Part I

Theory

2 Theory

Section 2.1 and 2.2 in Chapter 2 are taken from the authors specialization project, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1], as specified in Section 1.3.

2.1 Modelling and solution principles

The modelling principles can be sorted into two categories: deterministic and stochastic models, while solution methods can be distinguished between optimization and simulation. [14]

2.1.1 Deterministic and stochastic modelling

The two ways of deciding the value of input parameters and boarder conditions in a model is deterministic and stochastic modelling. The deterministic model are characterized by certainty; the parameters, start and final conditions are assumed to be known. Stochastic modelling takes uncertainties into account in the values of the parameters, the conditions and at the different stages of the process. Deterministic models will find a solution within the solution area the user has defined, and can be used for finding the boarder conditions and/or to point out the "right direction" for finding a solution while the stochastic modelling is suitable for finding the final solution. [14]

Deterministic and stochastic approach are used at short- and long-term modelling, respectively. The scope of a short term model is small, often both in geographical extension and in time, with a time horizon of typically days to weeks. Because of the short time horizon, the parameters can be assumed known, based on historical values and short-term forecasts. The scope of a long-term model is bigger, and hence more uncertainties are present. The typical time horizon is from months (season) and up to 3-5 years, and scenarios and probability distributions are used for the realization of each stage of the long-term modelling process. The scenarios are based on weather forecasts, historical values and prognoses from the TSOs. [14]

2.1.2 Optimization and simulation

Using optimization as solution method for a problem will result in a solution which is the best of many possible solutions. The best solution is found according to the objective function and constrains given for the problem. The decisions taken in one time step will impact all other time steps, also time steps before the active time step. The modelling of the problem is difficult, because all data needs to be accounted for; some variables may be hard to formulate while some data may be hard to provide. [14]

Simulation as solution method does not imply search for the optimal solution; simulation will search for one solution, but not necessary the best one (the optimal one). The solution will be user dependent, and hence based on experience and knowledge of the user. The problem is solved step by step, checking how the decision taken at this time will affect the future time steps. The decisions taken in the active time step will only impact future time steps, not previous time steps. Simulation is practical for investigating a few given scenarios, but is less practical when investigating big quantities of scenarios as it will results in ineffective use of time compared to running it as an optimization porblem. [14]

2.2 Optimization

2.2.1 The difference of global and local optimization

An optimization model can be local or global. A local model concerns only a small area relevant for a producer while the global model concerns a whole power system, e.g. Norway. The local model represents the producers' point of view, and has the objective function of maximizing the profit for the producer. The producer is a price taker, and the price of power is given as an input. The global model represents the systems point of view, and has the objective function to maximize the social welfare of the system, the sum of producer and consumer surplus, and fulfil the demand. The price will be an output given by the solution. [14]

2.2.2 Simplified, global model

The master project objective concerns Norway, and the global model will be used. The objective function is formulated to maximize the social welfare [1] for a given time horizon with respect to certain constraints. The reserve requirements will be included as one of these constrains, and the dual value of this constrain will represent the cost of the reserve requirement. This will be explained in the next sections.

Finding an optimal solution for the operation of the system is generally a complicated task. Therefore, simplifications are made to formulate and to solve the problem

[1] Also referred to as socioeconomic surplus

mathematically. The most important simplification for longer time horizons is using a linear model. The linear optimization, by the use of linear programming, allows the usee of linear relationships for the objective function and constraints of the problem that results in acceptable accuracy in results and a relative fast computation time for large scale problems. Further, all relevant data for production units, demand and transmission needs to be provided before solving the problem. To simplify, demand is represented as a fixed value for each time period within the total time horizon. The fixed value of demand is based on forecasts made by historical data of demand, inflow, temperature and meteorological forecasts. Because of the fixed demand, the surplus of the consumers fixed and cannot be maximized. When the consumer surplus is fixed the objective function can be simplified to concern only maximizing the surplus of the producers. Maximizing the producers surplus is the same as minimizing the cost of production.

The production units are characterized by their:

- Start-up and shutdown costs.
- Marginal cost of production, the cost of producing one more unit of power.
- Minimum and maximum production when in operation.

If wind and solar production are included in the model, the energy production are assumed fixed for the given time period and they are quantified by forecasts and historical data. They are usually included in the value of demand as negative demand for the respective time period. Transmission capacity is characterized with constrains for maximum capacity and can be aggregated between the areas in the model. [14]

2.2.2.1 Production optimization by minimizing production costs

In this section, the mathematical approach for modelling reserve requirement cost will be explained. The production optimization problem will be explained without reserve requirements before the reserve requirements will be added to the problem. The objective of Section 2.2 is to provide an explanation of the principle, and a simplified model is therefor considered: The simplified model consider one area and neglect transmission constraints, start-up and shutdown costs.

Nomenclature

i	Generator index, i = 1,k,I
t	Time period index, t = 1,k,T
C_{total}	Total cost of production
MC_i	Marginal cost of generator i

$Q_{i,t}$	Quantity produced from generator i in time period t
D_t	Demand in time period t
Q_i^{MAX}	Maximum capacity of generator i
Q_i^{MIN}	Minimum capacity of generator i
R_t	Reserve requirement, time period t

Mathematical model

The optimal production is given by minimizing the cost of production during the total time horizon. The problem can be formulated:

$$C_{total} = \sum_i \sum_t MC_i * Q_{i,t} \tag{2.1}$$

The total cost of the production during the whole time period is the sum of the marginal cost of production times the quantity produced for all generators in all time periods considered. The time horizon is divided into several load periods represented by t, which results in more realistic modelling and give different production requirements for each time period. But, because of the simplification, it only shows the average value of the predicted demand in this time period, and not the continuously, actual demand. To make the predicted demand as accurate as possible, the resolution of the time periods can be increased. This will however result in an increase of iterations for solving the problem and a high computation time. A trade-off will be needed.

The constraints taken into account are the requirement of balancing the system and the production capacity constrains for the generators:

$$\sum_{t,i} Q_{i,t} = D_t \tag{2.2}$$

$$Q_{i,t} \leq Qi^{MAX} \tag{2.3}$$

$$Q_{i,t} \geq Qi^{MIN} \tag{2.4}$$

Constraint (2.2) requires the sum of production in time period t to be equal to the demand in time period t. Constraint (2.3) and (2.4) requires the production from generator i in time period t to be less or equal to its maximum capacity and more or equal to its minimum capacity.

2.2.2.2 Including reserve requirements

Since reserve power is not produced power, an extra constrain is included to handle this requirement in the mathematical problem formulation. The reserve requirement is included by demanding that the power plants in operation has to produce below their maximum production limit, leaving a margin for power increase. The sum of the margin of all the generators in operation has to be equal or higher than the reserve requirement for the given time period. A similar constrain can be added for down regulation; demanding a margin between produced power and minimum production. The reserve requirement for up-regulation can be mathematically formulated in the following way:

$$\sum_{t,i}(Q_i^{MAX} - Q_{i,t}) \geq R_t \tag{2.5}$$

The reserve requirement (2.5) is placed together with the other constraints of the problem. In this way the choice of which generators should provide the reserve requirements in the given time period are decided in the optimization problem, with the objective to minimize the overall costs. The reserve requirements can be an input or a variable, e.g. a percentage of load for the given time period.

2.2.3 Results - optimal dispatch and dual values

After solving the optimization problem, results and dual values of the restrictions are obtained. The results give the dispatch of the generators to use during the respective time periods. The dual values are the cost of changing the right hand side of the constrain with one unit, and can be both positive and negative: A negative cost will be a gain that results in a reduction of the total cost, while a positive cost will increase the total cost. The dual value of each constrain is given for each of the time periods.

The dual value of the reserve constraint (2.5) will be the cost of increasing the reserve requirement, R, with one unit – in other words increasing the sum of the margin of production capacity with one unit. If the reserve requirement constraint (2.5) is binding, meaning that the sum of the difference between the maximum production capacity and the actual production is zero, the dual value of the reserve requirement will be different than zero. The dual value will be the cost of changing the dispatch of the generators, including a more expensive generator, to provide the requested margin.

An example of an optimization problem introducing the reserve requirement are provided in Appendix C.

2.3 Deciding cost of reserves by the socioeconomic surplus

The socioeconomic surplus is an economic term. It is the sum of the consumer and producer surplus in a market. The consumer surplus is the difference between what the consumers are willing to pay for a product and what they actually pay and he producer surplus is the difference between the price for which the producers are willing to produce the product and what they are actually payed. The socioeconomic surplus are illustrated in Figure 2.1.

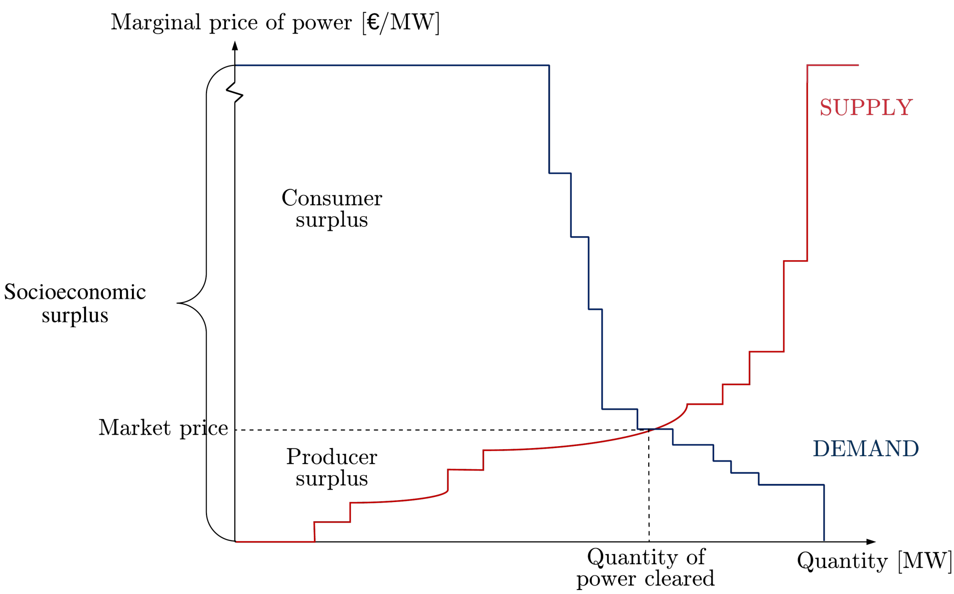


Figure 2.1: Socioeconomic surplus

The socioeconomic surplus are maximized in a market with perfect competition; by the equilibrium quantity, described as the *quantity of power cleared* in Figure 2.1. In this point, the demand and supply curve intercept, and the market price for the power is set.

The cost of reserves can be found by extracting the difference in socioeconomic surplus before and after adding the reserve requirement to the system. The cost of reserve per quantity is found by dividing the difference in SS by the quantity of reserves. The reserve cost can also be found per quantity hour, e.g. MWh, when divided by the numbers of hours in the time period the socioeconomic surpluses are given for.

2.4 Method for deciding reserve requirements

The Norwegian power system consist of a dominating share of HPP [2]. hydro power generators have optimal operation point [3] below maximum production and can be regulated up and down. This entail in a modest need for reserve requirements in the current power system; it is sufficient to set the reserve requirements equal to the loss of power in case of an outage a of the element holding the biggest capacity in the system, the biggest generator or transmission line, in operation [16]. The future Norwegian power system is expected to include an increased share of wind and solar power production. This involve that the variation and lack of regulation possibilities in the WPP and SPP has to be taken into account when setting the reserve requirements for the future system; it will be necessary to add additional reserves due to the larger variations in generated power when assuming that a significant share of the load is covered by WPP and SPP. The system must be able to handle an outage of the biggest element in the system *and* the variability due to WPP and SPP at the same time. The method concerning standard deviation of the wind and sun power production is used to find the additional reserves needed to provide increased flexibility in the power system simulated in the master project. This section will provide the theory of the method, while the actual numbers for reserves will be presented in Chapter 8.

2.4.1 Statistical approach based on standard deviation

The statistical approach of finding the (additional) reserve requirement use wind and load energy series as input data to find the distribution of variation in the load with and without the WPP. The standard deviation is then used to find the additional reserve requirement. The description of the method is based on the paper *Using Standard Deviation as Measure of Increased Operational Reserve Requirement for Wind Power* [12], which focus on estimating the effect of wind power on the short term reserves. The author of the master report has extended the method by including solar power production in addition to wind power production. The value of SPP is included by adding it to the value representing the WPP. Wind and solar power production are referred to as renewable power production, RPP, when added together.

Nomenclature

t	Time period index [hour], t = 2, k, 8760
P_t	Renewable power production in time period t
ΔP_t	Variation in RPP between time period t and t-1

[2] 92 % according to ENTSO-E [15]

[3] Optimal operation point corresponds to the output power with power factor closest to 1,0

L_t	Load in time period t
ΔL_t	Variation in load between time period t and t-1
NL_t	Net load in time period t
ΔNL_t	Variation in net load between time period t and t-1
σ	Standard deviation
μ	The mean value of the parameter during the total time period
x_t	The value of the parameter in time period t
n	Numbers of time periods during the total time period
σ_{NL}	Standard deviation of net load
σ_L	Standard deviation of load
σ_W	Standard deviation of WPP
σ_R	Standard deviation of RPP
I	The increase in reserves due to RPP
a	Confidence level

Mathematical model

In the statistical approach based on standard deviation, historical, hourly data of RPP and load during the year, P_t and L_t, are used to find the values of power and load variations during the year; ΔP_t and ΔL_t. [12]

$$\Delta P_t = P_t - P_{t-1} \tag{2.6}$$

$$\Delta L_t = L_t - L_{t-1} \tag{2.7}$$

The net load, NL_t, is the load with the RPP subtracted. Renewable power production can be considered as negative demand for the respective time period in a optimization model [14], ref. Section 2.2. The net load hourly variations, ΔNL_t, can be found from Equation (2.6) and (2.7).

$$NL_t = L_t - P_t \tag{2.8}$$

$$\Delta NL_t = NL_t - NL_{t-1} = (L_t - P_t) - (L_{t-1} - P_{t-1}) = \Delta L_t - \Delta P_t \tag{2.9}$$

However, the planning and operation of reserves in a power system are not based on a measurement on maximum variation, but on probabilities and risks. The reserves are determined so the variability are covered within a certain probability, here based on the standard deviation [12]:

The standard deviation, σ, is the average deviation of the value at the time step t and the mean value during the whole time period, x_t and μ, of a given parameter. [12]

$$\sigma = \sqrt{\frac{\sum_t (x_t - \mu)^2}{n}} \tag{2.10}$$

For a normal distributed probability function, the standard deviation will cover approximately 68 % of the deviations. In other words, 68 % of the variations obtained by the data is inside the range $\pm\ \sigma$. The range can be increased to cover a higher percentage of the variability: $\pm 3\sigma$ covers 99 % while $\pm 4\sigma$ cover 99.99 %. If the load and wind power production is assumed uncorrelated, the standard deviation of the net load time series can be found by Equation (2.11) [12]. In the extended method there is assumed no correlation between the load and the renewable power production, including the solar in addition to the wind, and Equation (2.11) is reformulated to (2.12).

$$\sigma_{NL} = \sqrt{\sigma_L^2 - \sigma_W^2} \tag{2.11}$$

$$\sigma_{NL} = \sqrt{\sigma_L^2 - \sigma_R^2} \tag{2.12}$$

The increase of reserves due to renewable power production is formulated as the difference between the standard deviation of the net load and the load, times the confidence level chosen, a. [12]

$$I = a * (\sigma_{NL} - \sigma_L) \tag{2.13}$$

Example

An example of a power system has a normal distribution curve shown in Figure 2.2, using 4 as confidence level. The maximum up-regulation is 52 MW, which derives from the maximum positive difference between load and net load, and maximum down-regulation is 152 MW, which derives from the maximum negative difference between load and net load. The increased reserve capacity is calculated 4*σ_{NL} - 4*σ_L = 1139 MW - 1063 MW = 76 MW. [12]

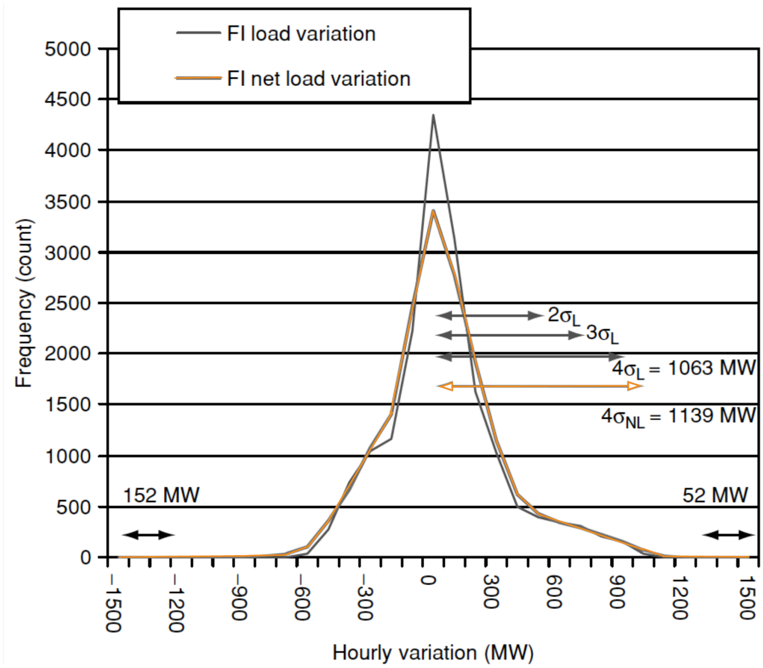


Figure 2.2: Example of a normal distributed variation curve, hourly variation sorted by frequency [12]

2.5 e-Highway2050 project

The overarching objective of the e-Highway2050 project is to develop a planning mythology in line with European energy policy for expanding the Pan-European electrical transmission network from 2020 to 2050. The project was initiated to support the European Union in reaching a low carbon economy by 2050. It is a research and innovation project supported by the EU Seventh Framework Programme and deals with the whole European power system, with a focus on the transmission network. The overarching objective has been split into nine individual objectives that are the target for nine individual work packages that together form the scope of the project. For each work package, a work package leader and contributors is chosen among the project partners. The e-Highway2050 project has 28 project partners; TSOs, research institutes, industry and consulting companies. [17] [9]

The work packages include strategy and scenario development for 2050; five energy scenarios have been developed to provide the possible future evolution of the European power system while meeting the 2050 low carbon economy orientation. The development of scenarios had contributions from several of the other project partners. This was necessary because developing a vision for 2050 is complex and compound, and has to include elements from economy, technology, policies and social behaviour. [17] [9]

From now on, the e-Highway2050 project will be referred to as e-Highway2050.

2.5.1 e-Highway2050 scenarios

The documentation for the e-Highway2050 project specify that "the scenarios developed are neither predictions nor forecasts; a scenario can be described as an alternative image of the future" [9], in this case the power system in 2050.

Developing scenarios

The first step when developing scenarios for e-Highway2050 was to identify the main uncertainties for the factors relevant for the future electrical power system in Europe, the boundary conditions. The main uncertainties and opportunities was narrowed down and combined into relevant strategies. Here, coherent factors [4] had to be taken into account. Then, assumed impact of a scenario was assessed to be able to reduce the number of possible scenarios; scenarios with similar impacts on the European power system was combined. [17]

The five e-Highway 2050 Scenarios

The description of the scenarios is cited directly from the e-Highway2050 project results [9] to provide an exact image of the five scenarios:

1. **Large scale RES:**
   The scenario focuses on the deployment of Large-scale RES such as projects in the North Sea and North Africa. GDP growth is high and electrification of transport and heating is very significant. The public attitude is passive resulting in low energy efficiency and limited demand-side management. Thus, the electricity demand is very high.
2. **100 percent RES:**
   This scenario relies only on RES, thus nuclear and fossil energy generation are excluded. High GDP, high electrification and high-energy efficiency are assumed. Storage technologies and demand side management are widespread.
3. **Big and market:**
   The electricity sector is assumed to be market-driven. A preference is thus given to centralised projects (renewable and non-renewable) and no source of energy is excluded. Carbon Capture Storage (CCS) is assumed to be mature.

[4] Here: Factors that are logically linked are called coherent factors. Example: If a technology is not commercially available in a given future scenario, it cannot be an option in the scenario.

GDP growth is high. Electrification of transport and heating is significant but energy efficiency is limited.

4. **Fossil and nuclear:**
De-carbonisation is achieved mainly through nuclear and CCS. RES plays a less significant role and centralised projects are preferred. GDP growth is high. Electrification of transport and heating is significant and energy efficiency is low.

5. **Small and local:**
The scenario focuses on local solutions dealing with de-centralised generation. GDP and population growth are low. Electrification of transport and heating is limited but energy efficiency is significant, resulting in a low electricity demand.

The key dimensions of the scenarios for 2050 are efficiency in technology and electrification of the transport sector within demand, variability and distribution of generation technology and electrical infrastructure for exchange of electricity. [9]

3 The EMPS model

The description of the EMPS model is based on Chapter 7 in the compendium of the course *ELK-15 Hydro power scheduling* [14] at NTNU fall 2016 and SINTEF manuals for the EMPS model [18] [19].

The EMPS model is a power market simulation tool with the goal of maximizing the socioeconomic benefit of a power system based on the water value method. The model is developed by EFI, the predecessor of SINTEF, and designed for stochastic optimization of the Nordic power system - a hydrothermal power system with a significant share of hydro power. The EMPS model is a long-term model with a simulation time horizon on 3-5 years, making the tool applicable for simulation of development of the power system and scenario analysis. This includes, among others, development and operational planning, price formation and environmental analysis. Regulators, TSOs, consultants, researchers and generation companies in the North European countries use the model. [18]

3.1 System model

3.1.1 Area modelling

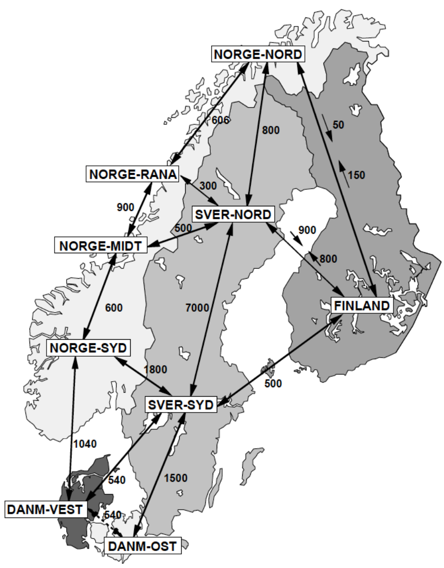


Figure 3.1: Example of areas modelled in EMPS [18]

The EMPS model is a multi-area model with areas connected with transmission lines. Figure 3.1 shows an example of an EMPS system model consisting of nine, interconnected areas. The user of the EMPS model has the possibility to define its own data set with the desired numbers of areas.

The main components within each area are hydro power production, wind and solar power production, thermal power production and demand, illustrated in Figure 3.2. [18]

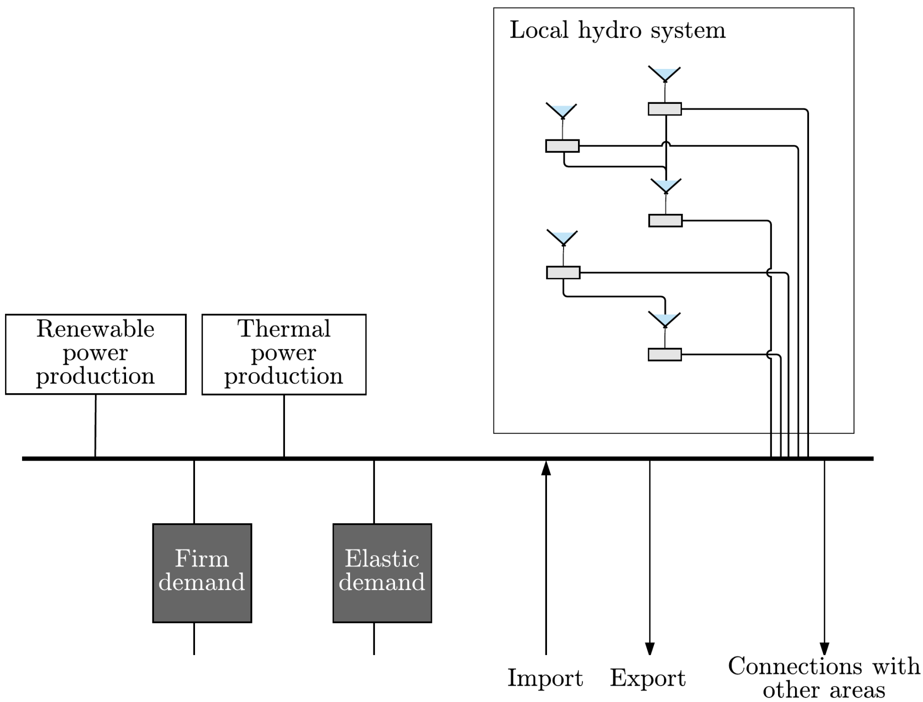


Figure 3.2: Local area model in EMPS [18]

3.1.2 Power production

Hydro power production

Hydro systems can be complex, as seen in the local hydro system in Figure 3.2, or contain a simple plant. Complex power systems will be reviewed in Section 4.1. Hydro power plants can be Run-of-River, without reservoirs, or have a reservoirs, but are all described by a standard module, illustrated in Figure 3.3. The standard module is composed by the reservoir, the power plant or gate (if no power production), inflow, bypass and spillage. The reservoir is described by its volume [Mm^3], storable and non-storable inflow by the amount of water per year [$Mm^3/year$], the power plant by the plant discharge capacity [m^3/s] and the energy equivalent [kWh/m^3] and the spillage and bypass by amount of water per second [m^3/s]. [19]

The storable inflow goes to the reservoir and can be used later. The non-storable inflow needs to be used immediately or continue as bypass. The spillage, bypass and plant discharge may go to a different reservoir or out of the system. The volume of water in a reservoir will equal zero at all times if the plant is Run-of-River. The plants may have minimum and maximum plant discharge volumes to comply with. [19]

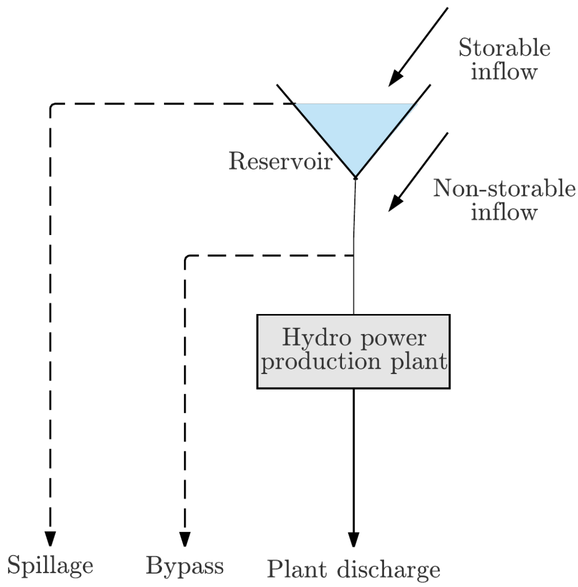


Figure 3.3: Standard module for hydro power plants in EMPS [18]

Thermal power production

Thermal power plants are price dependent generation, modelled by installed generation capacity [MW], availability during the year [hours], marginal production costs [€/MWh] and start- and stop-costs [€]. The variable production costs vary with efficiency, prices on fuel, maintenance costs and emission cost. [19]

Wind and solar power production

The wind power production is taken into account in the same way as Run-of-River hydro power: Wind power production is modelled as time dependent, negative demand in the relative area. It is represented by wind series, which represent the wind energy per 1 GWh/time unit. Weekly, daily or hourly time unit can be used.

The wind series are connected to a scaling factor where the installed capacity is specified. Solar power production can be modelled in the same way as wind power production. [18]

3.1.3 Transmission

The transmission lines between the areas are modelled by capacity [MW], (linear) electrical losses [percentage] and transmission fee [€/MWh]. These can depend on time. [18]

3.1.4 Demand

Loads consist of firm and elastic demand. The firm demand is represented by annual quantity, weekly profile during one year and a profile within the week. The elastic demand is price dependent and defined by a weekly profile and a disconnection price. This demand disconnects if the weekly spot market price exceed its disconnection price. Temperature dependency of the load can be included to simulate the influence of electrical heating in the Nordic countries, ref. Section A. [7] [19]

Batteries can be modelled in the EMPS model as a very flexible demand. Batteries are relevant for simulating future scenarios of the Norwegian power system but are not included in this master project.

3.2 Solution procedure

3.2.1 Strategy phase

The goal of the strategy phase is to decide values for the water in the reservoirs to be used in the simulation phase.

Aggregation of hydro modules

To be able to reduce the computation time to an acceptable value, the EMPS model aggregate all hydro modules in within one area to one, equivalent reservoir during the strategy phase. The water volumes are converted to energy in the aggregated model, because the different values one unit of water will have in the different reservoirs within the area, and then aggregated into the equivalent reservoir. The aggregated plant capacity is found by aggregating all maximum capacities. If the plants have discharge constrains, they have to be taken into account as restrictions for maximum and minimum production. Aggregated storable and non-storable inflow are calculated based on energy output and the difference in reservoir volume. [18]

Hydro inflow

The inflow variation is the major source of uncertainty for the future production in a hydro dominated area and can vary almost 100 % depending on if it is a dry or wet year, which was illustrated in Figure A.2 and discussed in Section A. The EMPS model includes this stochastic factor by letting the user include inflow data for 75 years, which includes dry, wet and average years of inflow.

Water values

The goal of the strategy phase is to establish expected values of stored water, water values, for the areas within the model. The water value can be described as "the cost of using reservoir water that could have been used for future hydro production" [14]. The water values are computed with Stochastic Dynamic Programming as a function of reservoir level and time. One water value is found for each aggregated area.

The water value for a given area is found by formulating a optimization problem with the objective to optimize the operation of the hydro power in the area by optimizing the use of stored water. The objective function is to minimize the operation costs week by week to the end of the planning period. To account for the stochastic inflow, the calculations of water values are run with all of the inflow scenarios. The final water values for each area are the weighted averages of the single inflow scenarios and used as the marginal cost of hydro power production in the respective area. [14] [7]

Calibration

The water values are computed for one area at the time, which implies that the areas are completely disconnected during the computation. This is however not true, and the exchange between the areas has to be taken into account. This is done by running a simulation of the full model and comparing the dispatch with the area model. If the difference is too big, some parameters are adjusted and the simulation is re-run. When the two simulations coincide, the water value calculation is finished. The adjusting is called to *calibrate* the model. The model cannot find the optimal solution without calibration. The EMPS model can be manually or automatically calibrated.

Manual calibration is based on experience of the user and done by adjusting the *feedback-*, the *form-* and the *elasticity factor*. The feedback factor decides the value of firm demand used to compute the water value in the respective area. If the value of firm demand increases, the water value increases, and will affect how the reservoir is handled. The form factor decides the annual load profile (the load distribution). If the form factor is increased, the demand is increased during the winter and decreased during the summer, forming shapes illustrated in Figure 3.4. A form factor equal zero gives a flat profile during the year. The elasticity factor decides the solution space of the reservoir handling. Low elasticity factor results in a small solution space. [14]

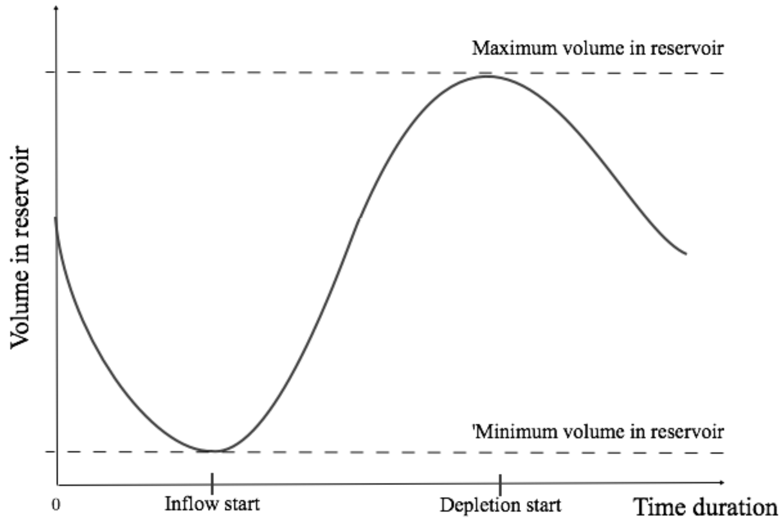


Figure 3.4: Optimal reservoir handling. Start of inflow and depletion season are marked.

Automatic calibration adjusts the same parameters according to an algorithm. The user can influence the automatic calibration by prioritizing and deciding the value of the steps when the parameters are adjusted. The objective of the automatic calibration is to maximize the socioeconomic surplus by using a stepwise solution procedure: The socioeconomic surpluses are checked when the parameters are adjusted. If the difference between the values before and after the parameters was adjusted is positive, the adjustments are continued, and if not, the model will try adjusting it the other way. If this also yields a negative variation, the adjustment is stopped, and the model moves on to the next parameter in the prioritized line. [14]

3.2.2 Simulation phase

The simulation phase can be divided into two parts: Area optimization and reservoir draw-down.

Area optimization

The area optimization model is a global model, taking all the areas in the model into account, and has the objective to find the optimal production strategy for the whole system; the optimal system dispatch. The optimization problem takes transmission cost and constrains, thermal production costs and capacity, and the characteristics of demand as input from user. In addition, the water values and end-of-week reservoir volumes are taken as input from the strategy phase. Since using the values of hydro from the strategy phase already includes stochastic factors, the model can solve the area optimization problem as a deterministic problem with the objective function to minimize production cost during the week. [14]

Reservoir draw-down model

After the aggregated strategy is decided, the detailed strategy for each reservoir is decided. The reservoir draw-down model distribute the aggregated hydro production between the reservoir in the respective area. The reservoirs are divided into two categories; buffer reservoirs and regulation reservoirs. Small magazines with low regulation factor, meaning that the annual inflow is significantly larger than the size of the reservoir, are often used as buffer reservoirs and run with different strategies than the regulation reservoirs. The regulation reservoirs follow a strategy that focus on minimizing the risk of spillage (full magazines) during melting season and minimizing the risk of capacity shortage (empty magazines) during depletion season. [14] The beginning of the inflow and depletion season is marked in Figure 3.4.

Coupling between the models

The area optimization model and the reservoir draw-down model is linked by feedback factors that decides when the convergence, and thus the optimal solution, is reached. The model run an iteration process, adjusting parameters and re-run the area optimization and reservoir draw-down, until optimal solution is found. [14]

3.3 Start-up costs and reserve requirements

This section is based on the technical report *Startkostnader og reservekrav i Samkjøringsmodellen* [13], SINTEF Energy.

Start-up costs and reserve requirements can be included in the EMPS model. They are represented only in the simulation phase, and not in the hydro optimization (strategy phase).

3.3.1 Start-up costs

Start-up costs for hydro units are usually small compared with the significant start-cost for thermal units. As the result of this, the EMPS model neglect the hydro start-up costs and includes only start-up costs for thermal units; the start-up costs are not included in the strategy phase, but are included as a characteristic for the thermal units in the simulation phase. The start-up costs are represented in the area optimization problem, and includes a variable showing if the unit was switched on in this time period and a parameter representing the start-up cost of the unit. The variable showing if the unit was on or off previous time period is a function of the same variable from previous time period, and can in this way determine if the unit went from off to on in this time period or not. A challenge is faced when moving to next week in the simulation: Because the area optimization problem is solved week by week, the model does not know if it is profitable to keep a unit running from last time period on Sunday to first time period on Monday next week. This problem is solved by using *round coupling*; by assuming that two consecutive weeks are very similar, the current week is used to predict if a unit will be in operation in the first time step in the next week. If a unit is not in operation in the last time period of Sunday, start-up costs will be included if the same unit was in operation in the first time period on current weeks Monday.

From accumulated to sequential price segments

Load periods are described with price segments. Table 3.1 shows an example of the price segments, or load periods, during a week. They are called *accumulated price segments* as their succession is insignificant and equal load periods can be accumulated.

Table 3.1: Example: Accumulated price segments used to describe the load

Day of the week	Time	Price segment
	00-08	(3) Night/morning
Monday - Friday	08-14	(1) Peak
	14-00	(2) Afternoon/evening
Saturday - Sunday	All hours	(4) Weekend

When adding start-up cost, the sequence of the load periods becomes of significance, and the model has to use *sequential price segments* when optimizing the weeks in the simulation. The amount of price segments in the model is changed from four (accumulated) to sixteen (sequential) as the model only can merge load periods that are equal *and* consecutive. The sequential price segments from the example are illustrated in Figure 3.5 [1].

[1]Figure 3.5 is only an illustration and does not reflect real values of load

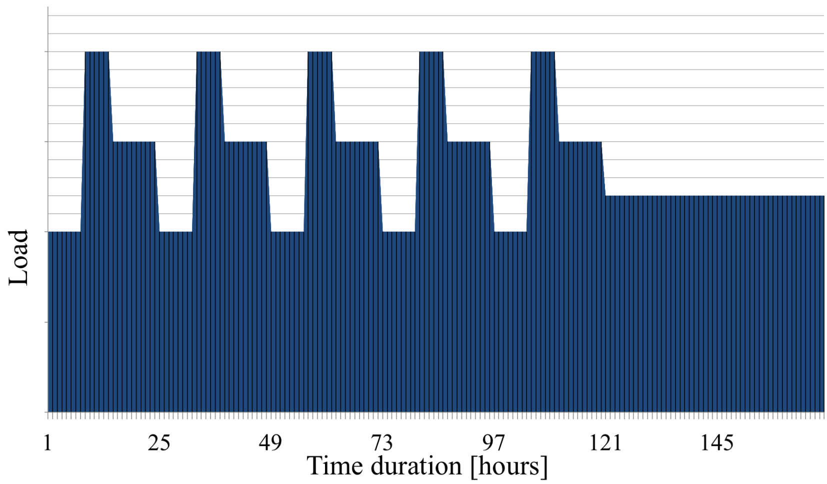


Figure 3.5: Illustration of price segments used to describe the load during one week

Accumulating days with equal sequential price segments

The model can accumulate days with equal load pattern; the same units will be used to fulfill the load in the time span of the respective days. In this example, Tuesday, Wednesday and Thursday can be accumulated. Monday and Friday cannot be included, as the dispatch is different in the weekend and may include to switch on or off units on Monday and/or Friday.

3.3.2 Reserve requirements

Reserve requirements are set in [MW] for each week of a the year or simulation period. The requirements can be given per area, for groups of areas and/or for the system as a whole. It is possible to enable several of mentioned requirements at the same time. Reserve requirements are expected to affect the marginal price of power; the system be forced to start an extra unit to fulfil the reserve requirements, and in this way the marginal price of power will be increased.

Dependency on start-up costs

The reserve requirements are dependent on the start-up costs: Without start-up costs, all units can function as reserve unit according to the optimization problem, independent of the unit is in operation or not. This can be explained mathematically by the variables included in the reserve requirement: The reserve requirement is composed by the minimum production, the maximum production and the quantity of reserves, as presented in Section 2.2. Because the minimum and maximum production capacity is introduced in the start-up costs, the reserve requirement are dependent on the start-up costs.

Hydro power as reserves

Hydro power are defined as part of the reserves without being producing at the time as the hydro power generators have no start-up costs. The reserve restriction presented in Section 2.2 are extended to

$$\sum_{t,i}(Q_i^{MAX} - Q_{i,t}) + \sum_{t,j}(Q_j^{MAX}) \geq R_t \tag{3.1}$$

where the last part of the equation on the left hand side is describing the hydro power generation. The maximum production of power from the hydro power generators are restricted by the volume of water in the reservoirs and the generator capacities. The nomenclature presented in Section 2.2 is upgraded to

i	Thermal generator index, i = 1,k,I
j	Hydro power generator index, j = 1,k,J

Simplifications and limitations

The EMPS model simplifies the handling of reserves and only requires a reserve capacity [MW] per week. The model does not include an application for dividing the different reserve products in the Norwegian balancing markets; the primary, secondary and tertiary reserves, discussed in Section B.2, or the functionality of deciding the reserve requirement for a smaller time period than one week.

The need for mixed integer programming (MIP) when introducing start-up cost to represent if units are on or off are *simplified with linear restrictions* as simulations with MIP are time consuming and increase the computation time significantly. [13]

Start-up and shut-down time can also be included in the optimization of the dispatch of a system, but are not included in the reserve functionality in the EMPS model and hence not for the master project.

Increased computation time

Adding reserve requirements increase the calibration and computation time [13]. In case of simulation of a large and complex power system, the increase in computation time can be significant. A project scope including several scenarios that are to be calibrated and run with different values and a limited processor capacity to run the model can result in high, accumulated computation time.

Printing the dual value of the reserve requirement

The reserve application in the EMPS model has been extended to print the cost/price of reserves for each price segment of the year for all inflow years. The costs of reserves are represented by the dual value of the reserve requirement. The dual value of the reserve requirement is set to be 500 €/MWh if the reserve requirement is not fulfilled. The extension was executed by Arild Helseth, SINTEF Energy and co-supervisor in the master project.

3.4 Programs/applications for processing of results

Samutskrv print results from the simulation in the EMPS model in text or table format. The results are given per node, or area, and per week for each of the inflow scenarios [18]. For the master project, the relevant results are the reservoir volumes, which are used to calibrate the model, ref. Chapter 5. *Kurvetegn and pckurvetegn* are used to illustrate results graphically in the EMPS model. They are specially designed to fit the results from the EMPS model. *Samoverskudd* extract the socioeconomic surplus of the simulations run in the EMPS model [18]. Socioeconomic surplus are used to automatically calibrate the EMPS model and, relative to the master project, used to quantify the cost of reserves.

Part II

Data set

4 Original data set

SINTEF Energy provided the data set used as a starting point in the master project. Chapter 4 describes the data set with the original input while Chapter 6 describes the data set with the modified inputs, the scenarios. The author hopes in this way to provide the reader with a clear understanding of the process of the project.

The data set consist of four areas and the structure of the data set is illustrated in Figure 4.1. The data set will be referred to as *4del* and the areas will be referred to as nodes from here on. Three of the nodes, Node 1, 2 and 3 are representing the Norwegian system, while Node 4 represent (Central) Europe.

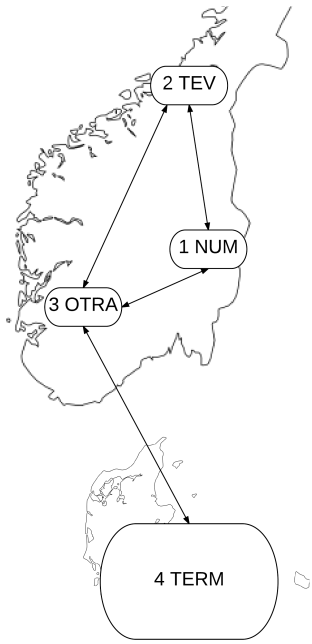


Figure 4.1: 4del data set, area model

Table 4.1: Description of nodes in 4del

Number of node	Short name	Full name	Country/Region
1	NUM	Numedal	Norway
2	TEV	Trondheim	Norway
3	OTRA	Otra	Norway
4	TERM	Thermal area	(Central) Europe

4.1 Hydro systems

Detailed hydro systems

Numedal, Trondheim and Otra are hydro dominated areas and contain detailed hydro systems within the nodes. The detailed hydro system is illustrated in Figure 3.3 and referred to as local hydro system. As explained in Section 3.1.2, each hydro module is described by a standard module composed by reservoir size, storable and non-storable inflow, plant discharge, generator capacity, value of spillage and bypass [19]. A local hydro system is a network of hydro modules, linked together via the waterways.

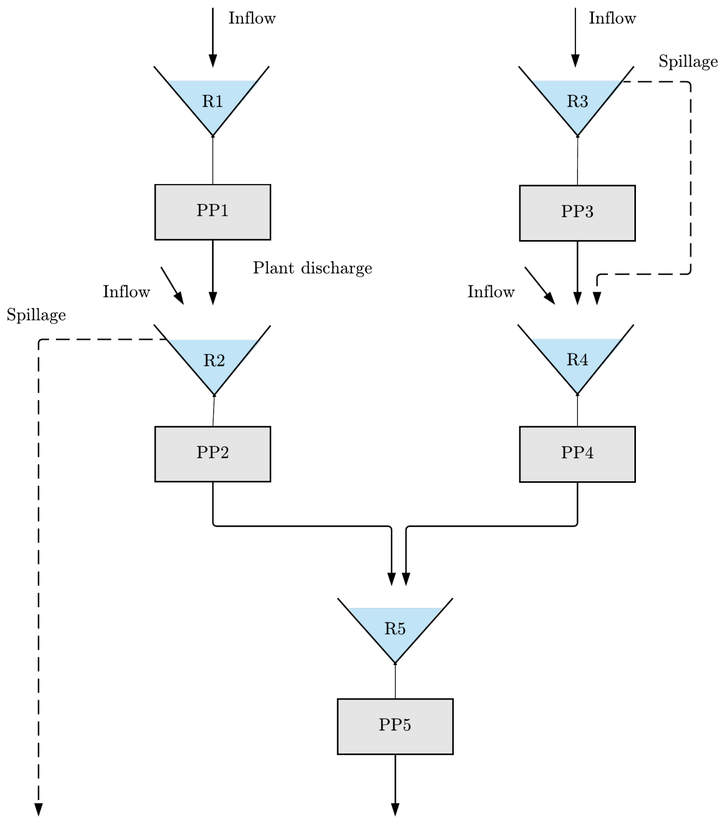


Figure 4.2: Example: Detailed hydro system in EMPS

Figure 4.2 illustrates an example of hydro links in an hydro power system: The plant discharge of PP1 is part of the inflow of reservoir R2. R2 cannot handle all inflow and have spillage that disappears out of the system. Spillage and plant discharge from reservoir R3 are part of the inflow in reservoir R4. Plant discharge from PP2 and PP4 are inflow in R5. It is clear that the state of the reservoirs and power plants are dependent on each other. The detailed hydro system in each of the nodes of 4del are illustrated in Appendix D.1

Characteristics of hydro systems in 4del

Hydro inflow is described by inflow series over 50 years. The regulation reservoirs in all nodes follow the following strategy; the filling season is during week 18-40 and the depletion season is during week 40-18. The characteristics of the hydro systems within NUM, TEV and OTRA are presented in Table 4.2.

Table 4.2: Data concerning hydro power generation in the nodes

	NUM	TEV	OTRA	TERM
Number of reservoirs	17	12	21	0
Aggregated reservoir capacity [GWh]	1 529,70	1 607,13	2 857,91	0
Number of power stations	14	12	8	0
Aggregated hydro production capacity [MW]	610,24	535,29	819,51	0

4.2 Demand and market

A summary of the description of the demand and market in the original 4del data set follows. A detailed description of the input data can be found in Appendix D.

4.2.1 Demand

Firm power, fixed demand

Table 4.3: Fixed demand [GWh/year] in simulation period

	NUM	TEV	OTRA	TERM
Firm power, general supply	2 000,00	2 000,00	2 500,00	-
Firm power, industry 95	925,00	82,51	500,00	-
Firm power prognosis	-	-	-	1 000,00
SUM	2 925,00	2 082,51	3 000,00	1 000,00

In NUM, TEV and TERM, the demand is valid for each of the periods of 52 weeks with the total simulation period of 156 weeks; week 1-52, 53-104, 105-156. In OTRA, Fastkraft, industri 95 is only present in the first period, week 1-52. In the two following periods, the value of the Fastkraft, industri 95 is 0 in OTRA.

Load profiles

The loads follow yearly and weekly profiles. The yearly profile describes the weekly behavior of the load during one year, while the weekly profile describe the behaviour of the load with one week. The profiles are pre-programmed and included in the original data set. One yearly and weekly profile are illustrated in Figure 4.3: Firm power prognosis as yearly profile and General supply as weekly profile. The profiles fit the Norwegian load pattern with a higher demand in the time periods with colder temperature; the increase in load are due to increased use of energy for space heating, ref. Appendix A.

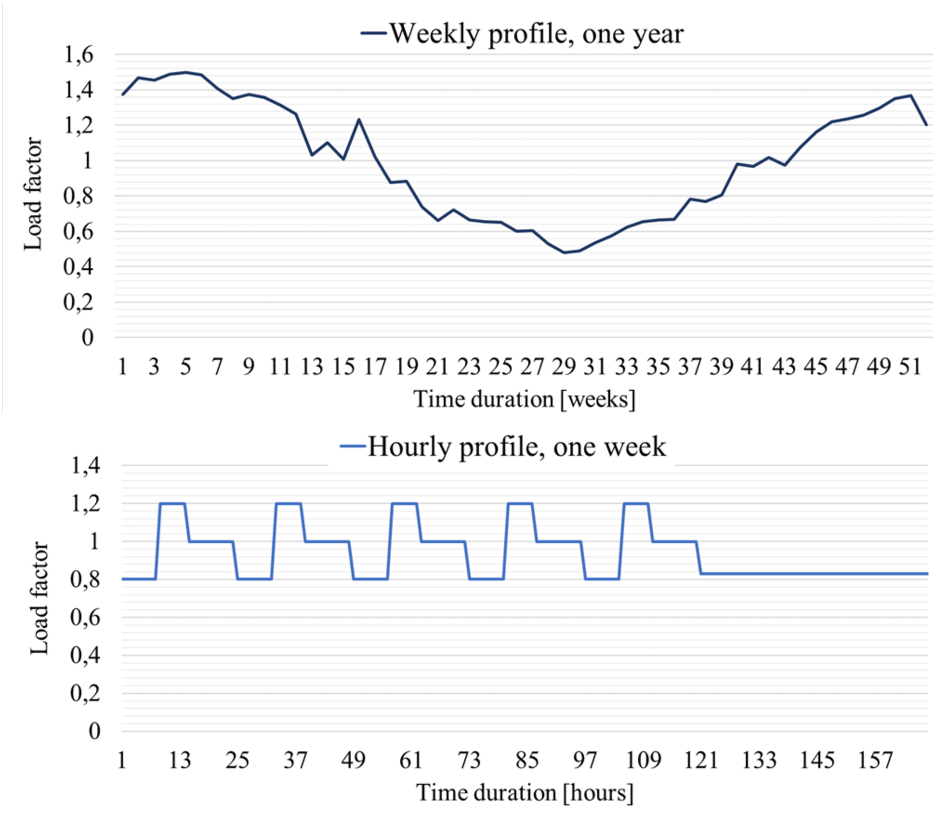


Figure 4.3: Load profiles included in the data set: Firm power prognosis as yearly profile and General supply as weekly profile

Temperature series

No temperature time series are related to the demand.

Price dependent demand, elastic demand

No price dependent market was initially present in the data set.

Price segments

The following price segments are used to describe the variation in demand:

Table 4.4: Price segments used to describe the load. Valid for all nodes.

Day of the week	Time	Price segment
	00-08	(3) Night/morning
Monday - Friday	08-14	(1) Peak
	14-00	(2) Afternoon/evening
Saturday - Sunday	All hours	(4) Weekend

The file describing the price segment for each hour of the week is rendered in Appendix H.2.

4.2.2 Generation

The total generation in the nodes are given in Table 4.5. All the generation have 100 % availability.

Table 4.5: Generation capacity [MW]

Node	Thermal	Hydro	Total installed capacity [MW]
NUM	5,12	610,24	0,58
TEV	-	535,29	
OTRA	-	819,51	
TERM	130,00	-	130,00

Start-up costs

Only one unit is charged with start-up costs; the unit "VARME, startkostnad" has an installed capacity of 50 MW, has a minimum capacity of 10 % of the installed capacity and has a start-up cost of 100 000 NOK.

Wind and solar power production

No wind or solar power production were initially present in the data set.

Rationing and flooding

All of the nodes have flooding and rationing costs, which is modelled as generation. The flooding makes sure that the prices are not negative in case of full magazines. Flooding can be manually included, but will be automatically included if not. The cost of flooding is included manually in the nodes TEV and TERM at a cost of 0,01 €/MWh, and automatically included in the other nodes. The rationing is the cost for cutting the load. Table 4.6 lists the rationing price in the system.

Table 4.6: Cost of rationing [øre/kWh]

Node	Category, name	Price [øre/kWh]
NUM	Rationing	362
TEV	Rationing	445
OTRA	Rationing	350
TERM	Rationing	445

4.2.3 Exchange

Table 4.7: Exchange volume [GWh]

Node	Category, name	Exchange [GWh]	Week	Price [øre/kWh]
TEV	Salgtrinn, Kjelkraft25	30,00	1-156	24,6
OTRA	Kjøpstrinn, Varmekraft	0,44	1-156	1,0
	Kjøpstrinn, Varmekraft	0,10	1-156	4,0
	Kjøpstrinn, Varmekraft	0,26	1-156	10,0
	Kjøpstrinn, Varmekraft	0,17	1-156	15,0
	Kjøpstrinn, Varmekraft	0,83	1-156	17,0
	Kjøpstrinn, Varmekraft	0,78	1-156	40,0
TERM	Salgtrinn, Kjelkraft25	30,00	1-104	24,0
	Salgtrinn, Kjelkraft25	30,00	104-156	26,0

4.3 Transmission

The transmission lines between the nodes are described by capacity [MW], (linear) electrical losses [%] and transmission fee [øre/kWh] and described in a data file included in the data set [18]. The transmission capacity is given in Table 4.8. The transmission capacities are equal for all price segments.

Table 4.8: Transmission capacity between the nodes [MW]

from \to	NUM	TEV	OTRA	TERM
Numedal	-	200	200	-
Trondheim	200	-	200	-
Otra	200	200	-	150
TERM	-	-	150	-

The losses in the transmission lines are set to be zero for all lines except the line between OTRA and TERM, which is set to be 3 %. This line can be assumed to be an undersea cable. The transmission fee is set to be 0.001 øre/kWh for all of the lines. The transmission fee is only symbolic and does not have any impact on the results when sat to these values. The data file describing the characteristics of the transmission lines can be found in Appendix D.3

4.4 Reserve requirement

The reserve requirement is 111 MW for a group containing Node 1, 2 and 3 (NUM, TEV and OTRA). The requirement applies for the whole simulation period, week 1-156.

5 Development and implementation of the scenarios

This chapter describes the development and implementation of the scenarios. The first and second section describe the usage of data from the e-Highway2050 project [10] and the assumptions for the input data, while the following section describe the implementation and calibration of the scenarios in the EMPS model.

Overview of the scenarios

Three scenarios have been chosen from the pole of scenarios provided by the e-Highway2050 project, described in Section 2.5:

X5	Large scale RES
X7	100 % RES
X16	Small and local

5.1 Relation between e-Highway2050 and 4del

Data from the e-Highway2050 project are used to decide the types and values of production and demand in the scenarios. The e-Highway data set [10] are divided into *clusters*, illustrated in Figure 5.1. For each cluster, generation and demand are aggregated.

To be able to use the data from the e-Highway project in the master project, the clusters, depicted in Figure 5.1, are related to the nodes in the EMPS data set, 4del, depicted in Figure 4.1. Data from one or two clusters in the e-Highway data set are used to describe each of the nodes in 4del. Clusters representing South and Middle Norway represents the three nodes in Norway while Denmark west and Germany north represents the Thermal node. The relation between the two data sets are summarized in Table 5.1:

Table 5.1: Relation between clusters (e-Highway) and nodes (4del)

e-Highway cluster number	Node in 4del
82NO + 80NO	1 NUM
83NO	2 TEV
81NO + 79NO	3 OTRA
38DK + 31DE	4 TERM

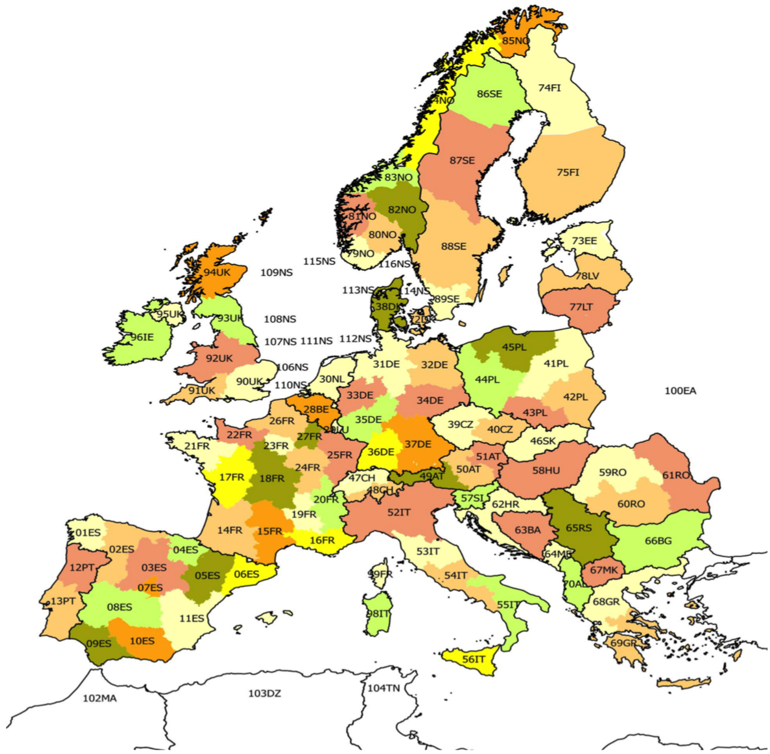


Figure 5.1: e-Highway cluster map [10]

5.2 Assumptions and limitations

5.2.1 Generation technologies

The data obtained from e-Highway2050 [10] specify installed capacities and demand in clusters. The production technologies are wind, PV (photo voltaic solar power) and CSP (concentrated solar power), nuclear, biomass, gas (open cycle, with CCS and without CCS), coal (with CCS and without CCS), lignite (with CCS and without CCS), run of river (ROR), pumped storage power (PSP) (with and without reservoir) and hydro with reservoir.

Because of expected technologies for 2050 scenarios in the chosen clusters, the use of a simplified EMPS data set and the reduction of complicity by reducing the number of inputs in the data set, the author, in consultation with her supervisors, decided to aggregate the production technologies. In addition, the modification of the hydro systems are time consuming and challenging due to the detailed description and modelling of the hydro systems in the original data set, ref. Section 4.1 and D.1. In consultation with her supervisors it was decided that the modification of the hydro system were outside the scope of the master project. From this follow that the original hydro systems and capacities are assumed fixed for the data set and the list of production technologies are reduced to the following:

- RES: Wind, PV [1] (photo voltaic solar power)
- Thermal: Biomass, gas, coal and lignite[2]
- Hydro

With the fixed hydro capacity given in Table 5.2.

Table 5.2: hydro power generation capacity [MW]. Valid for all scenarios.

	NUM	TEV	OTRA	TERM
Aggregated hydro production capacity	610,24	535,29	819,51	-

5.2.2 Scaling of capacities from e-Highway2050

As the hydro capacities in the 4del data set are assumed fixed for all scenarios, and listed in Table 5.2, it follows that the data for generation capacities and demand in cluster 79NO, 80NO, 81NO, 82NO and 83NO given in the e-Highway documentation has to be scaled into 4del-values in the hydro dominated areas. The method used for scaling of data from e-Highway to 4del is described in Appendix E.

Cluster 31DE and 38DK form TERM, which represents "the rest of Europe". The real numbers of production and demand within this node are not important, as the exchange between Norway and Central Europe is limited by the capacity in the transmission line between OTRA and TERM, L4. In theory, the production capacity and demand in Node TERM can be "infinite" without affecting the Norwegian nodes besides though the transmission capacity in L4. The capacities from cluster 31DE and 38DK are directly used in Node TERM without being scaled.

5.2.3 Marginal cost of production

The data deciding the prices for the technology in 2050 are taken from the World Energy Outlook 2016 [11], published by the International Energy Agency, and

[1] Also referred to as solar power production

[2] Lignite power production capacity is zero for all nodes in all scenarios and will be excluded from the following descriptions of the generation

TYNDP2016 [20]. Data from Current Policy Scenario 2040 [11] was used for EU power generation data (emission factors) and data from Vision 3, year 2030, [20] was used for fuel and CO2 prices. Lignite is neglected due to zero capacity in all scenarios. The generation costs are included in the model in øre/kWh by assuming 1 € = 10 NOK and 1 ¢/MWh = 1 øre/kWh.

Table 5.3: Data related to computation of marginal price of generation

		Hard coal	Oil	Gas
CO2 price	[$/tonne CO2]	71,00	71,00	71,00
Emission factor	[Mtonne/TWh]	0,97	0,93	0,41
Fuel price	[€/netGJ]	2,80	13,26	7,23

1 kWh = 3,6 MJ and assuming 1 $ = 0,915 € [21]. Biomass are assumed to be priced 22 €/MWh.

Table 5.4: Marginal price [€/MWh] for generation

	Hard coal	Oil	Gas	Biomass
CO2 cost	63,02	60,42	26,64	
Fuel cost	10,08	47,74	26,03	
Marginal cost, MC	73,10	108,16	52,67	22,00

5.2.4 Start-up costs

Start-up costs are modelled by the following assumptions [22]:

Table 5.5: Start-up cost [€/MW] used for generation technologies

	Hard coal (> 500)	Hard coal (≤ 500)	Gas	Biomass
Start-up cost	49	105	24	0

The start-up costs are calculated by multiplying the start-up costs per installed MW for the relative technology with the installed capacity. The start-up costs are included in the model in øre/kWh by assuming 1 € = 10 NOK.

5.2.5 Wind and solar energy series

The wind and solar time energy implemented in the scenarios are obtained from the e-Highway project. The author was able to obtain the data in cooperation with

Ingeborg Graabak, SINTEF Energy. The orange curve in Figure 5.2 illustrates the power curve used to convert wind resources to power.

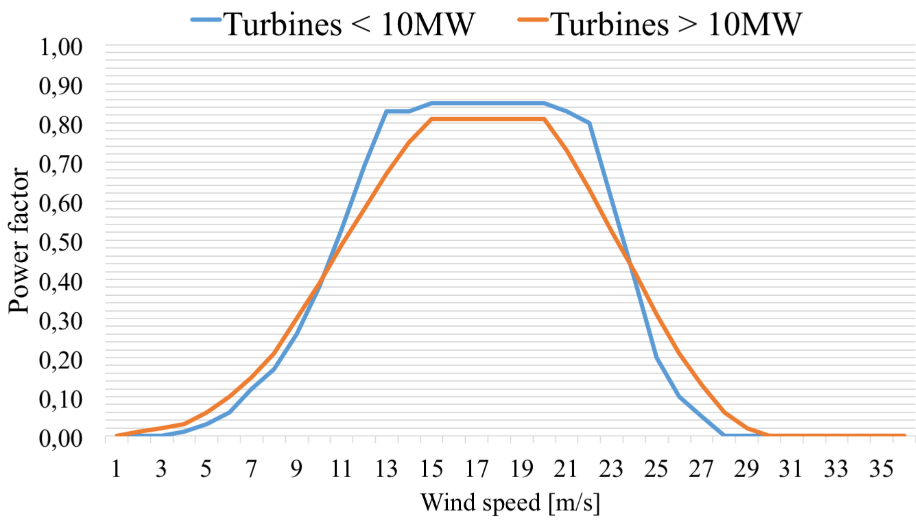


Figure 5.2: Power curve used to convert wind to wind power production. Maximum power factor, pf = 0.81.

For each of the nodes in 4del, energy series from the clusters (e-Highway) are used to describe the wind and solar power production per 1 MW installed capacity for each hour within the nodes (4del). When implemented, the files containing the energy series are linked to a scaling factor to match installed capacity in the relevant cluster. The link between the energy series and installed capacity are described in Appendix H.3. The energy series contain energy series for each hour of five year, and have their base in measured data in the time period 2011-15. Time series was obtained for both geographical points within the clusters and for the aggregated clusters. The time series from the aggregated clusters was found to be best suited for its purpose as the system are analysed from a broad perspective.

Energy series from the aggregated clusters

The aggregated energy series for wind and sun are a representation of the wind or sun in the whole geographical area representing the cluster, and not just one point within that area. In other words, even if it doesn't blow one place within the cluster, it can blow another place within it - making the aggregated value of wind different from zero. A larger geographical spreading of the installed wind power reduce the variability and result in a smoother energy series, which increases the accuracy of the wind power forecasts. The geographical area of the clusters are represented in Figure 5.1.

5.3 Implementation and calibration

Table 5.6 list the generation and demand data given after the scaling of the data from e-Highway2050:

Table 5.6: Scaled e-Highway2050 generation and demand data

Generation [MW]	X5	X7	X16
NUM	947,4	973,2	740
TEV	872,2	937,7	644,3
OTRA	943,3	971,5	902,7
TERM	61 105,6	71 161,5	56 110,5

Demand [GWh/year]	X5	X7	X16
NUM	3 401,3	2 600,6	3 579,0
TEV	2 460,0	1 881,3	2 589,2
OTRA	1 392,8	1 064,9	1 465,6
TERM	164 887,0	134 657,0	93 626,0

Section 3.2.1 explain the need for calibrating the EMPS model after implementation of the data. The calibration process is an iterative process where, when the reservoir handling is found to not be optimal, the calibration parameters are adjusted and the model is re-calibrated. The user will aim for optimal reservoir handling, illustrated in Figure 3.4. The reservoir handling should follow a seasonal curve with a focus on avoiding empty reservoirs in the depletion season, week 40-18, and avoiding full reservoirs in the filling season, week 18-40, as this imply lost incomes and therefor not an optimal strategy.

The following sections will provide a summary of the implementation and calibration process in the making of the scenarios. Percentiles present the reservoir handlings: 0, 25, 50, 75 and 100 percentiles of the reservoir handling during the year for the 50 inflow scenarios. A percentile is a curve in which indicate the value where the relative percentage of the observations fall under. For example: The 25 percentile indicate that 25 % of all observations fall under this value for each time step. The power prices are presented by the mean values of the power prices in each of the nodes.

5.3.1 Implementation and calibration process

The implementation and calibration process are explained by the execution of the process on scenario X5.

After implementing the input data discussed in the previous sections, the model was automatically calibrated and re-run. The definition of auto-calibration includes running the automatic calibration procedure in the model without taking the start-up costs into account, while the running of the model includes the start-up costs. This is elaborated in Section 5.3.2. The reservoir handling in scenario X5 with scaled values from e-Highway2050 are illustrated in Figure 5.3. The percentiles indicate poor handling of the reservoirs, with a strategy resulting in flooding of the reservoirs in over 50% of the inflow scenarios in the inflow season for the Norwegian nodes. TERM has no hydro power, and the value is zero at all time. The reservoir handling was improved by manually calibrating the model by adjusting the feedback factor for the nodes. In the initial reservoir handling of scenario X5, the feedback factor for TEV and OTRA needed to be decreased.

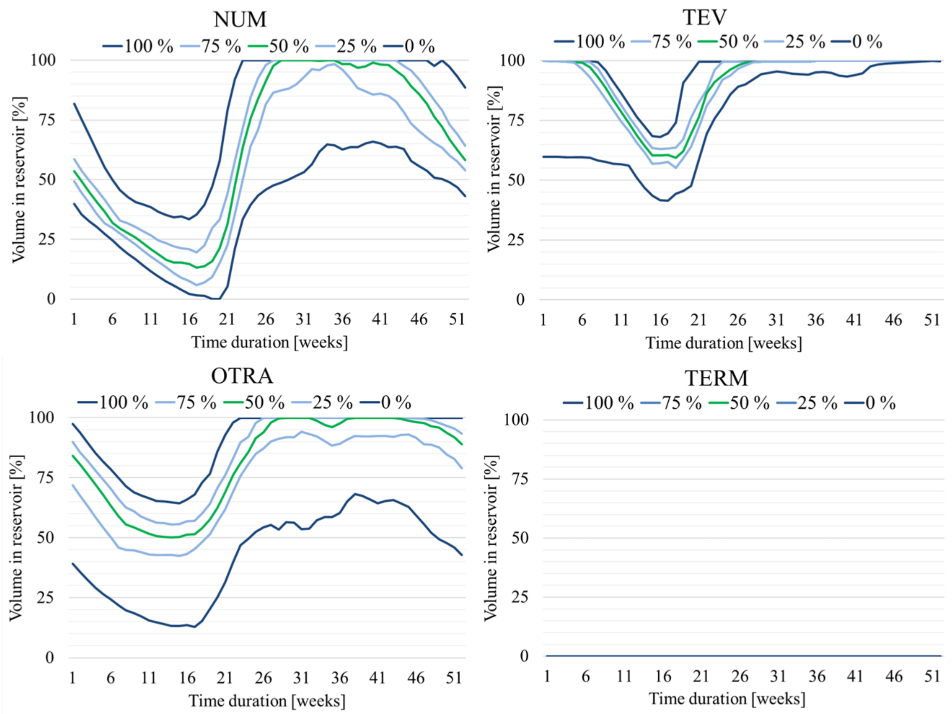


Figure 5.3: Initial handling of reservoirs in scenario X5 with scaled values from e-Highway2050

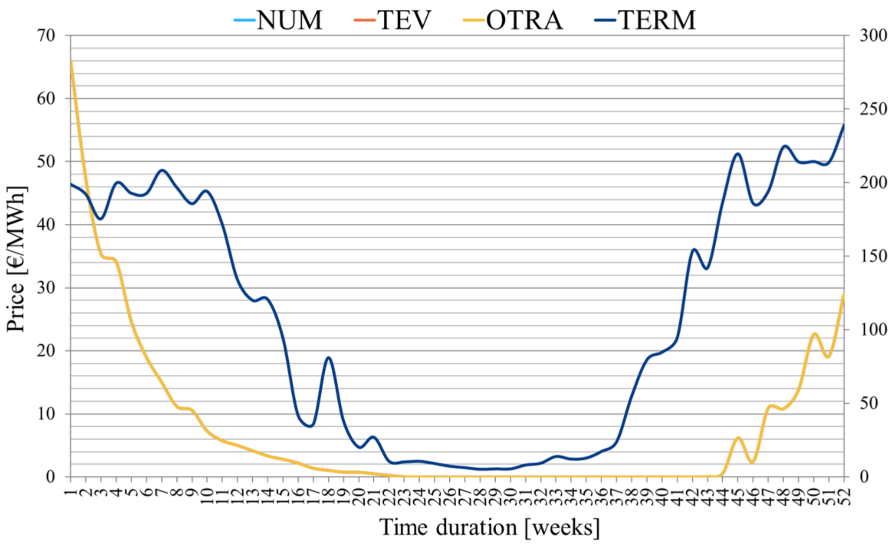


Figure 5.4: Initial mean power prices [€/MWh], scenario X5 with load at scaled e-Highway2050 values

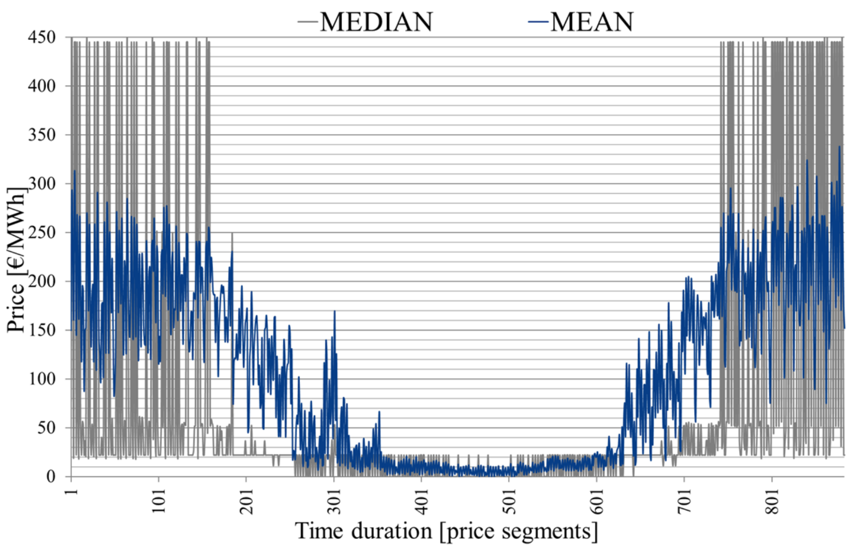


Figure 5.5: Mean value and median of power prices [€/MWh] per price segment in TERM, scenario X5 with load at scaled e-Highway2050 values. 17 price segments equals one week.

The mean power prices are illustrated in Figure 5.4. The author wants to make reader aware that the prices in NUM, TEV and OTRA are relative to the primary y-axis, while the prices in TERM are relative to the secondary y-axis. The prices in

TERM are high. When investigating the price in TERM by looking at its mean power price versus median of the power price, Figure 5.5, it is clear that TERM is not able to fulfil its demand in most of the inflow scenarios. As TERM does not have any hydro and maximized the transmission cable between OTRA and TERM in the same share of the inflow scenarios, this is due to the variation in sun and wind, given in the energy series: TERM have over 90% wind and sun. When the wind does not blow or/and its cloudy, TERM have only a minor of its total generation. This result in rationing price of 445 €/MWh in the dominating share of the inflow scenarios, and hence are reflected in the median of the power price.

To be able to get the prices in TERM on an acceptable level, the demand in TERM was decreased to 70% of the value from the scaled e-Highway2050 data due to over 90% wind and solar power in TERM in the scenario. After the new value for the load in TERM was implemented and the manually calibration of the feedback factor, the model was auto-calibrated. The new auto-calibration was done to improve the dispatch of the system: With improved initial feedback factors and TERM in a more balanced state, the auto-calibration is able to find a better dispatch than after the first auto-calibration. After the second auto-calibration, the author improved the reservoir handling by manually adjusting the feedback factors for the areas, aiming for optimal reservoir handling. The final reservoir handling of the reservoirs in scenario X5 can be found in Appendix F.

The process was repeated for scenario X7 and X16. In scenario X7 and X16, the load in TERM was adjusted to 85% and 90% of scaled e-Highway2050 value for demand. The initial and final reservoir handling in scenarios X7 and X16 can be found in Appendix F.

Summary: Process of implementation and calibration for the scenarios

1. Implement e-Highway data relative to scenario.

2. Auto-calibrate the model (without start-up costs) and run the model (with start-up costs).

3. Evaluate the reservoir handling, the prices and the use of the transmission lines between the nodes. Adjust the demand in TERM and the feedback factor and re-run the model (with start-up costs).

4. Auto-calibrate the model (without start-up costs) and run the model (with start-up costs).

5. Manually adjust the feedback factors, aiming for optimal reservoir handling and re-run the model (with start-up costs).

6. Repeat 5. until sufficient reservoir handling are obtained.

5.3.2 Limitations and sources of error

Several limitations and sources of errors can be connected to the development of the scenarios, the implementation and calibration process:

1. *Simplification of the system:* The clusters in e-Highway2050 forms a complicated power system with a high degree of interconnection between the clusters. When transferring only a handful of the clusters to form a new system, 4del, the high degree of interconnection is lost. The clusters are now more dependent on balancing the energy within the node, with a lower degree of interconnection. This dependency of balancing is taken into account by decreasing the load in TERM in the scenarios, but remain a significant source of error.

2. *Deciding the value of the demand in TERM:* The author decided the value for the load in TERM by testing values and deciding for an acceptable level of the prices in TERM in the three scenarios. Optimal choice of value of demand in TERM can not be guaranteed.

3. *Automatic calibration without start-up costs:* In consultation with her supervisors, the author chose to use automatic calibration without taking start-up costs and reserve requirements into account. The choice of using automatic calibration has its origin in lack of experience for the author. The choice of calibrating without start-up costs reduces the calibration time with almost 12 hours, from 12,5 to 0,5 hour, and, after the manual calibration, provides sufficient optima. The input parameters used for automatic calibration can be found in Appendix H.4.

4. *Manual calibration:* When manually calibration of the model, the feedback factors are the only factors adjusted. The form- and elasticity factors are not adjusted manually, but kept at values set by the automatic calibration.

5. *Human interaction:* Because the calibration includes human interaction, optimal reservoir handling can not be guaranteed. Also, the degree of the quality of the reservoir handling for the three scenarios cannot be guaranteed to coincide.

6. *Series simulation:* The master project uses series simulations in the running of the reservoirs: Start volume for the reservoir in the simulation year is set to the reservoir volume in the end of last simulation year [18].

6 Modified data sets: Scenarios

6.1 Common data, valid for all scenarios

Detailed hydro systems

The detailed hydro systems within each of the nodes, discussed in Section 4.1 and illustrated in Appendix D.1, are included in the scenarios without any modifications.

Renewable generation

Wind power production and solar power production are modelled as one plant for wind and one plant for solar in each cluster. The overview of the relation between cluster and nodes can be found in Table 5.1 and the input files can be found in Appendix H.3. The wind and solar power production have no price, but are subtracted from the firm demand used in the calculation of the water values. This gives the wind and solar power production an indirect price of zero.

Thermal generation

The biomass is implemented as one generator per node. Gas is divided into small and big generators, 250 MW and 500 MW. Coal is divided into small and big generators, 200 MW and 600 MW. The price is set by taking the marginal cost of the general generation technology into account and assuming a higher marginal cost for smaller generators. For the gas generators, a step of 1 €/MWh between each 250 MW generator and 0,5 €/MWh between each 600 MW generator are assumed. For the coal generators, a step of 0,5 €/MWh between each coal generator are assumed. It is assumed that all generators have P_{MIN} at 20 % of P_{MAX}.

Start-up costs

Table 6.1: Implemented start-up costs for generation

Technology	Installed capacity	Marginal Csu [€/MW]	Csu [€]
Gas	250	24	6 000
	500	24	12 000
Hard coal (≤ 500)	200	105	21 000
Hard coal (> 500)	600	49	29 400

Table 6.1 list start-up costs by technology and installed capacity. The start-up costs are calculated with the marginal start-up costs given in Table 5.5 as basis. Wind, solar and biomass have start-up costs equal zero, and are not listed in the table.

Rationing and flooding

The cost of flooding and rationing are the same as for the original data. They are explained in Section 4.2 and listed in Table 4.6. In addition, a cost for not fulfilling the reserve requirement is added in relation to the extension of printing the dual value of the reserve requirement. The cost of not fulfilling the reserve requirement is 500 €/MWh.

Demand

The demand is given for three equal time periods of 52 weeks within the total simulation period of 156 weeks; demand volume per year. The profile during the year and within the week is the same for the demand in all nodes; Firm power prognosis (Fastkraftprognose) as yearly profile and General supply (Allmenn forsyning) as weekly profile. The profiles are illustrated in Figure 4.3. There are no temperature profiles or cut-out prices connected to the loads; the demand can only be cut by rationing.

Exchange

The author has assumed that the exchange volumes from the original 4del data set are relevant to the 4del scenarios. The quantity and price (assuming 1 € = 10 NOK) are directly transferred to the scenarios. The exchange is equal to the original 4del data set and given in table 4.7.

Transmission

The transmission constrains are equal to the transmission constrains in the original data set, ref. Section 4.3: The capacity between the Norwegian nodes are 200 MW while the capacity between OTRA and TERM are 150 MW. The losses in the transmission lines are set to be zero for all lines except the line between OTRA and TERM, which is assumed to be an undersea cable, and set to be 3 %. The transmission capacities are equal for all price segments and given in Table 4.8.

Price segments

The price segments are the same as presented in Table 4.4. When including start-up costs, 17 sequential price segments form one week and 884 price segments form one year. The file describing the price segment for each hour of the week is rendered in Appendix H.2. During the simulation, three days are accumulated; Tuesday, Wednesday and Friday, ref. Section 3.3.

6.2 Scenario X5: Large scale RES

A summary of the description of Scenario X5: Large scale RES follows. A detailed description of the scenario can be found in Appendix G.

Table 6.2: Generation capacities [MW], scenario X5

Node	Wind	PV	Biomass	Gas	Coal	Hydro
NUM	290,3	6,4	13,5	26,9	0	610,3
TEV	326,3	10,6	0	0	0	535,3
OTRA	119,2	4,6	0	0	0	819,5
TERM	45 827,8	10 027,8	3 250,0	4 000,0	1 600,0	0

Table 6.3: Demand volume [GWh], scenario X5

Node	Category, name	Demand volume	Week number
NUM	FIRM, Demand	3 401,3	1-52, 53-104, 104-156
TEV	FIRM, Demand	2 460,9	1-52, 53-104, 104-156
OTRA	FIRM, Demand	1 392,8	1-52, 53-104, 104-156
TERM	FIRM, Demand	115 420,9	1-52, 53-104, 104-156

6.3 Scenario X7: 100 % RES

A summary of the description of Scenario X7: 100 % RES follows. A detailed description of the scenario can be found in Appendix G.

Table 6.4: Generation capacities [MW], scenario X7

Node	Wind	PV	Biomass	Gas	Coal	Hydro
NUM	239,2	111,1	12,6	0	0	610,3
TEV	299,0	103,4	0,0	0	0	535,3
OTRA	98,8	53,2	9,8	0	0	819,5
TERM	46 039,5	16 122,0	6 250,0	2 750,0	0	0

Table 6.5: Demand volume [GWh], scenario X7

Node	Category, name	Demand volume	Week number
NUM	FIRM, Demand	2 600,6	1-52, 53-104, 104-156
TEV	FIRM, Demand	1 881,3	1-52, 53-104, 104-156
OTRA	FIRM, Demand	1 064,9	1-52, 53-104, 104-156
TERM	FIRM, Demand	114 458,5	1-52, 53-104, 104-156

6.4 Scenario X16: Small and local

A summary of the description of Scenario X16: Small and local follows. A detailed description of the scenario can be found in Appendix G.

Table 6.6: Generation capacities [MW], scenario X16

Node	Wind	PV	Biomass	Gas	Coal	Hydro
NUM	129,7	0	12,6	0	0	610,3
TEV	109,0	0	0	0	0	535,3
OTRA	53,2	0	9,8	0	0	819,5
TERM	30 235,4	18 325,1	3 750,0	3 000,0	800,0	0

Table 6.7: Demand volume [GWh], scenario X16

Node	Category, name	Demand volume	Week number
NUM	FIRM, Demand	3 579,0	1-52, 53-104, 104-156
TEV	FIRM, Demand	2 589,2	1-52, 53-104, 104-156
OTRA	FIRM, Demand	1 465,6	1-52, 53-104, 104-156
TERM	FIRM, Demand	84 263,4	1-52, 53-104, 104-156

6.5 Comparing the data sets; the original data set and the scenarios

6.5.1 Generation and demand

Table 6.8 provides an overview of the generation and demand data per node for all of the data sets; the original data set and the scenarios. The generation have been increased in all nodes in the three scenarios, compared with the original data set. The demands are variable in the scenarios, and NUM, TEV and OTRA are shifting between increasing and decreasing in the different scenarios. TERM has been redefined from a small node to a node modelling Central Europe, and has increased it generation capacity and demand relative to its new definition.

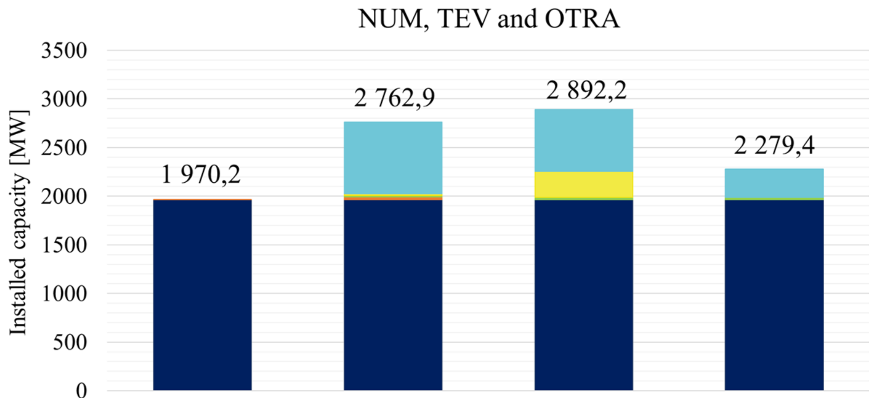
Table 6.8: Generation and demand, all data sets

Generation [MW]	Original	X5	X7	X16
NUM	615,4	947,4	973,2	740
TEV	535,3	872,2	937,7	644,3
OTRA	819,5	943,3	971,5	902,7
TERM	80,0	61 105,6	71 161,5	56 110,5

Demand [GWh/year]	Original	X5	X7	X16
NUM	2 925,0	3 401,3	2 600,6	3 579,0
TEV	2 082,5	2 460,0	1 881,3	2 589,2
OTRA	2 500,0*	1 392,8	1 064,9	1 465,6
TERM	1 000,0	115 420,9	114 458,5	84 263,4

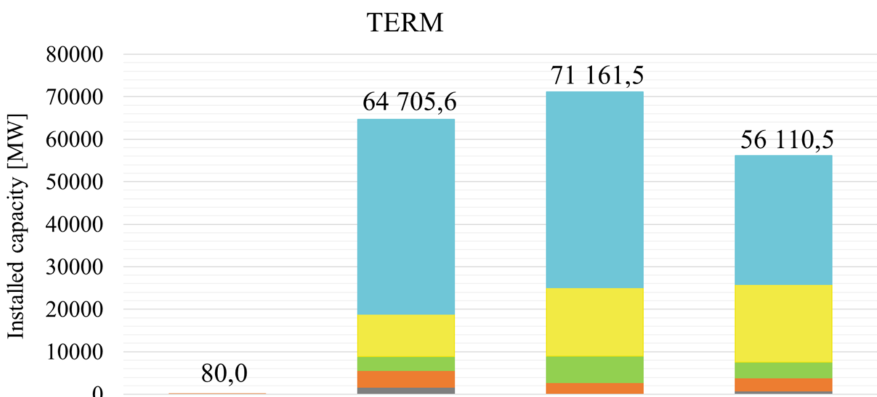
*In the original data set, OTRA have 3 000,0 GWh/year in week 1-52 and 2 500 GWh/year in week 53-156 in the simulation period.

The values of production from the technologies are summarized and illustrated in Figure 6.1 and 6.2. The developed scenarios have been extended to include biomass, wind, solar (PV) and coal power production. Figure 6.1 illustrates that the nodes in the Norwegian area have a significant share of hydro; hydro power production provide 99,7 %, 71,2 %, 67,9 % and 94,2 % in the original data set, X5, X7 and X16. Figure 6.2 illustrates that TERM has been redefined, including that its production capacity has been multiplied by hundreds. The redefinition has included the change from a pure thermal node to a thermal node with significant share of wind and solar power production.



	Original	X5	X7	X16
Wind	0	735,8	637	291,9
PV	0	21,6	267,7	0
Biomass	0	13,5	22,4	22,4
Gas	5,12	26,9	0	0
Coal	0	0	0	0
Hydro	1965,1	1965,1	1965,1	1965,1

Figure 6.1: Production [MW] in NUM, TEV and OTRA, all data sets



	Original	X5	X7	X16
Wind	0	45827,8	46039,5	30235,4
PV	0	10027,8	16122	18325,1
Biomass	0	3250	6250	3750
Gas	80	4000	2750	3000
Coal	0	1600	0	800
Hydro	0	0	0	0

Figure 6.2: Production [MW] in TERM, all data sets

6.5.2 Price curves

As a results of the change in types of production, capacities and values of demand, the power prices have different trends and values during the year. Figure 6.3 illustrate the mean value of the power prices in the nodes in the Norwegian area and TERM in the original data set and as an average for the scenarios. The Norwegian prices, NOR, are relative to the primary axis while the prices in TERM are relative to the secondary axis.

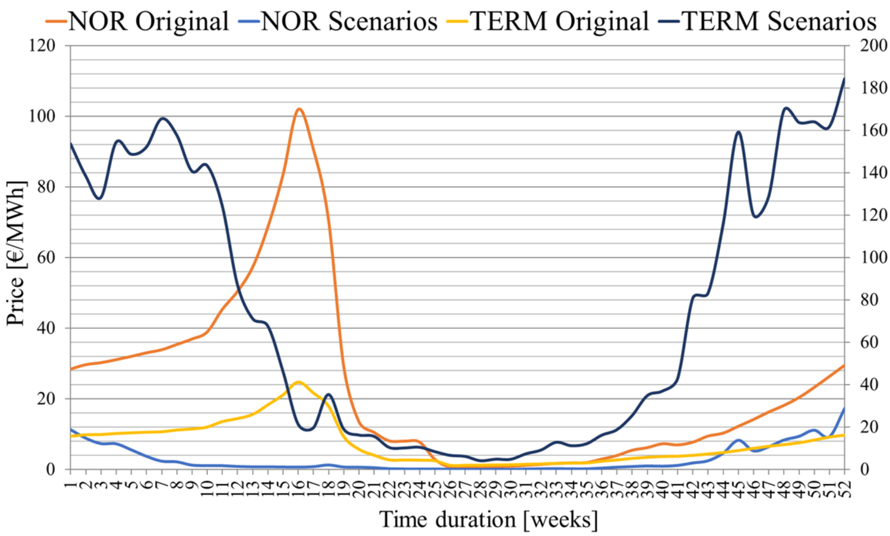


Figure 6.3: The mean power prices [€/MWh] in the Norwegian area, NOR, and TERM in the original data set and an average of the scenarios

The Norwegian power prices has an higher, average power price in the original data set than in the scenarios, although the prices coincide in the middle of the inflow period, where the prices are close to zero. The power prices in TERM are higher in the scenarios than in the original data set.

Part III

Analysis

7 Description of cases

The scenarios are calibrated without start-up cost but simulated with the start-up costs after the calibration, as described in Chapter 5.3. The models are re-run after each adding of reserve requirements, but not re-calibrated after the initial calibration. The numbers are extracted from the EMPS model by assuming that 1 øre/kWh = 1 €/MWh.

7.1 Case I: Prices of reserves

Case I has the objective to quantify the cost of reserve procurement in the three scenarios. By extracting results from before and after adding the reserve requirement including the power produced from the largest active element in the system and the variation due to renewable power production, the costs of the reserve procurement can be quantified. The cost is quantified by comparing the socioeconomic surplus and the dual value of the reserve requirement constraint included in the optimization problem. The effect on the power prices in the system will be evaluated.

7.2 Case II: Sensitivity analysis

Case II has the objective to perform sensitivity analysis on the scenarios by investigating the trends of reserve prices (dual values), total socioeconomic surplus and power prices when increasing the reserve requirement with multiples of the initial values found in Case I. The reserve requirement will be multiplied with 2, 3, 4 and 10. By including all three scenarios, the findings will be evaluated based on their differences in power portfolio and value of demand in addition to validate or contradict the results found in the other scenarios.

7.3 Case set-up

The presentation of the cases is divided into four parts: In the first part, theoretical information basis and/or calculations of necessary parameters are performed. In the second part, the results from the simulations are presented. In the third part, the results are discussed, and in the fourth part, the main results and outcome of the discussion are summarized.

Regarding the presentation of results

The results from the simulations are presented per scenario.

The dual values of the reserve requirement are extracted from the EMPS model by an extension implemented by Arild Helseth, co-supervisor of the master project. The extension prints the dual value of the reserve requirement for each price segment during the year. The dual values are presented graphically and referred to as the *reserve price*. The marks on the x-axis mark the start of each week, and the label on the x-axis marks the start of each month.

Socioeconomic surplus are given for each node and as the sum of the socioeconomic surplus. The sums of the socioeconomic surplus are referred to as total socioeconomic surplus, or total SS, and are the sums of the surplus in the nodes. They are represented as the mean values of surplus calculated over the inflow years and are extracted by operating the application Samoverskudd in the EMPS model.

The power prices are illustrated as the weekly average during one year. The author wants to make reader aware that the power price curves are given with two y-axis in Case I: The prices in NUM, TEV and OTRA are relative to the primary axis, while the price in TERM is relative to the secondary axis. In Case II, the power prices are given as a mean value of the power prices in the three Norwegian nodes NUM, TEV and OTRA. The prices are given for each value of the reserve requirement, R, for the relative scenario. The prices in TERM are not included in the illustration of power prices in Case II.

In Case II, the first week of the year is intentionally left out. The values of reserve prices and power prices in the first week of the year did not correspond to the values in the rest of the year in any of the cases of R in both of the prices, with prices close to zero in all cases of R for all scenarios.

The data extracted from the EMPS model has been processed in Excel by the author. The EMPS model produce large amounts of data in which are hard to use without processing, which is why developing macros in Excel was needed before the results and outcomes of the model could be presented graphically.

8 Case I: Quantify value of reserves

8.1 Calculation of reserve requirements

The reserve requirements are calculated for the Norwegian region, NUM, TEV and OTRA. The reserve requirement is decided for each scenario, and given by the largest element, transmission line or generator, in operation in the region [16] plus the value of the reserves due to wind and solar power production variation in the system. The calculation of the increased reserve requirement due to wind and solar power production variation was executed based on the theory presented in Section 2.4 [12]. The confidence level, a, is chosen to 3, which covers 99 % of the variations when using normal distribution for the standard deviations [12]. The values of the standard deviation for load, net load and renewable (wind and solar) power production are listed in Table 8.1.

Table 8.1: Standard deviations for load, σ_L, net load, σ_{NL}, and renewable power generation, σ_R, [MW], all scenarios

	X5			X7			X16		
NUM	132,0	133,3	18,6	100,9	102,6	18,6	138,9	140,1	18,6
TEV	139,1	140,7	21,0	106,4	108,4	21,0	146,4	147,9	21,0
OTRA	222,7	223,6	20,6	170,2	171,5	20,6	234,3	235,2	20,6
TERM	12 852,1	26 086,2	22 700,5	12 822,9	26 071,8	22 700,5	9 272,4	24 521,2	22 700,5

The values of the reserve requirement for scenario X5, X7 and X16 are presented in Table 8.2. The largest, active element in the system is the hydro power station Brokke, which hold an installed capacity of 305,9 MW. Brokke is indexed as power station number 11511 in the hydro system within OTRA, which is illustrated in Figure D.3, Appendix D.1. The increased reserves due to wind and solar power production in each of the nodes are in the range 2,71-6,16 MW. The sum of the reserve requirement for each scenario is referred to as *R0* for the relative scenario.

Table 8.2: Theoretical reserve requirements [MW] for the Norwegian region, all scenarios

	X5	X7	X16
$R_{biggestelement}$	305,90	305,90	305,90
I_{NUM}	3,89	5,07	3,10
I_{TEV}	4,72	6,16	4,49
I_{OTRA}	2,85	3,73	2,71
Sum, R0	317,36	320,86	316,20

8.2 Presentation of results

8.2.1 Scenario X5: Large scale RES

The dual values of the reserve requirement of R = 317,36 MW in scenario X5 gives the reserve prices illustrated in Figure 8.1. The reserve prices are generally close to zero, but have exceptions during the middle and end of the year. These exceptions are however brief, and varies between low price, near zero, and a price at 10-11 €/MWh. The mean value of the reserve price during the year is 1,041 €/MWh.

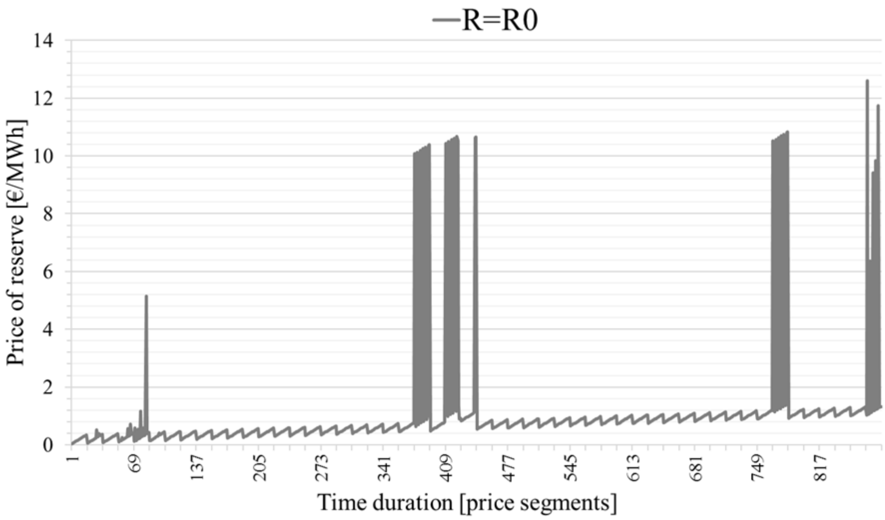


Figure 8.1: Reserve prices [€/MWh], scenario X5 and R = 317,36 MW. 17 price segments forms one week.

The socioeconomic surplus in scenario X5 with R = 0 MW and R = 317,36 MW = R0 are given in Table 8.3.

Table 8.3: Socioeconomic surplus [k€], SS, scenario X5 with R = 0 MW and R = 317,36 MW

	NUM	TEV	OTRA	TERM	Total
SS, R = 0 MW	1 230 756	1 096 755	541 981	48 715 222	51 584 712
SS, R = 317,36 MW	1 230 728	1 096 724	542 018	48 715 216	51 584 681

As the difference in total SS represents the cost of the reserve requirement, the total cost for the reserve requirement is 31 k€, or 31 000 €. This equals a cost of 97,68

€/MW and 0,011 €/MWh of reserve. The socioeconomic surplus for each node are represented in Table 8.3. The reserve requirement resulted in decrease of surplus in NUM, TEV and TERM, while an increase of surplus in OTRA.

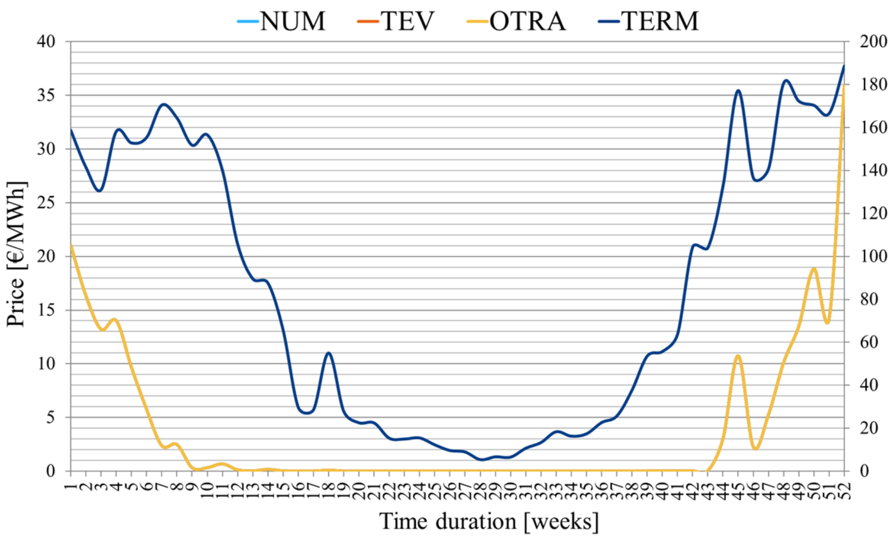


Figure 8.2: Mean, weekly power prices [€/MWh], scenario X5 and R = 0 MW

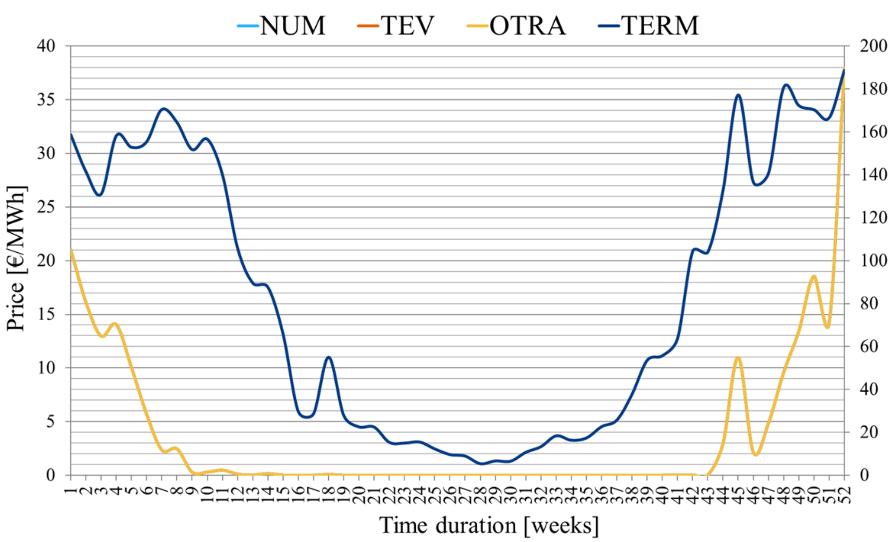


Figure 8.3: Mean power prices [€/MWh], scenario X5 and R = 317,36 MW

Figure 8.2 and 8.3 presents the power prices before and after adding the reserve requirement. The power prices are not sufficient affected by adding the reserve requirement that visual differences can be seen in the graphs. The prices are low, especially in the inflow season, week 18-41. The prices in NUM, TEV and OTRA, represented by the yellow graph in both Figure 8.2 and 8.3, are low in the preceding and succeeding weeks of the inflow season in addition to the weeks during the inflow season. The highest price of the Norwegian nodes are found in week 52, with a power price at approximately 35 €/MWh. The average price in TERM is approximately 150 €/MWh in the depletion season, week 1-18 and 40-52, and 7-10 €/MWh in the inflow season.

8.2.2 Scenario X7: 100 % RES

The dual values of the reserve requirement of R = 320,86 MW in scenario X7 gives the reserve prices illustrated in Figure 8.4. The reserve prices are lower than in scenario X5, but with exceptions during week 21-28, price segments 358-477. The exceptions are more stable than in scenario X5, with a price of 10-50 €/MWh during the whole period. The mean value of the reserve price during the year is 4,186 €/MWh.

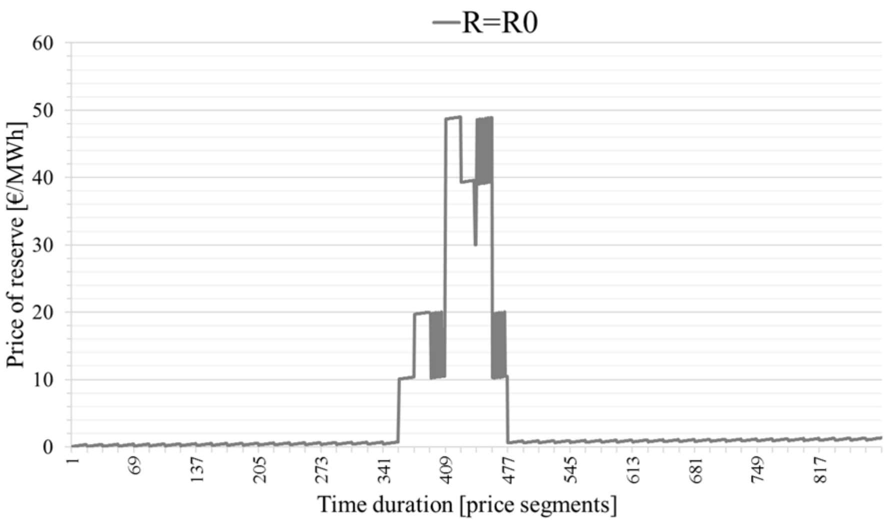


Figure 8.4: Reserve prices [€/MWh], scenario X5 and R = 320,86 MW. 17 price segments forms one week.

The socioeconomic surplus in scenario X7 are given in Table 8.4. The difference in total SS is 7 k€, 7 000 €, which equals a cost of 21,82 €/MW and 0,003 €/MWh of reserve. This is a lower change in surplus and hence cost of reserve than in scenario

X5. The reserve requirement resulted in decrease of surplus in NUM and TEV, while an increase of surplus in OTRA and TERM.

Table 8.4: Socioeconomic surplus [k€], SS, scenario X7 with R = 0 MW and R = 320,86 MW

	NUM	TEV	OTRA	TERM	Total
SS, R = 0 MW	941 459	837 459	418 225	48 989 072	51 186 219
SS, R = 317,36 MW	941 453	837 453	418 230	48 989 078	51 186 212

The power prices are generally lower than the power prices in scenario X5. Similar to scenario X5, the prices are highest during the depletion season, especially in the beginning and end of the year. Unlike in scenario X5, prices are close to zero during a longer time period, from week 6 to week 51. The power prices in TERM are similar in shape and value to the power prices in scenario X5 in the depletion season, with an average value of 150 €/MWh. The prices are lower than scenario X5 during the inflow season, with a price of less than 5 €/MWh in the middle of the year, week 23-32.

A small visual difference can be seen in the power prices when adding the reserve requirement of 320,86 MW; the highest price of power, found in week 52, decreases from approximately 0,54 to 0,14 €/MWh. No other differences in the power price are recorded. The prices before and after the reserve requirement are illustrated in Figure 8.5 and 8.6.

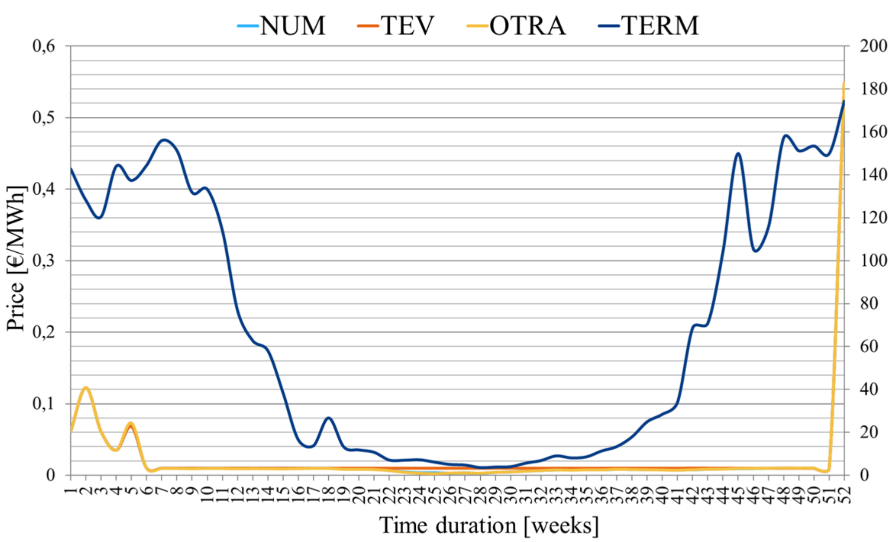


Figure 8.5: Mean, weekly power prices [€/MWh], scenario X7 and R = 0 MW

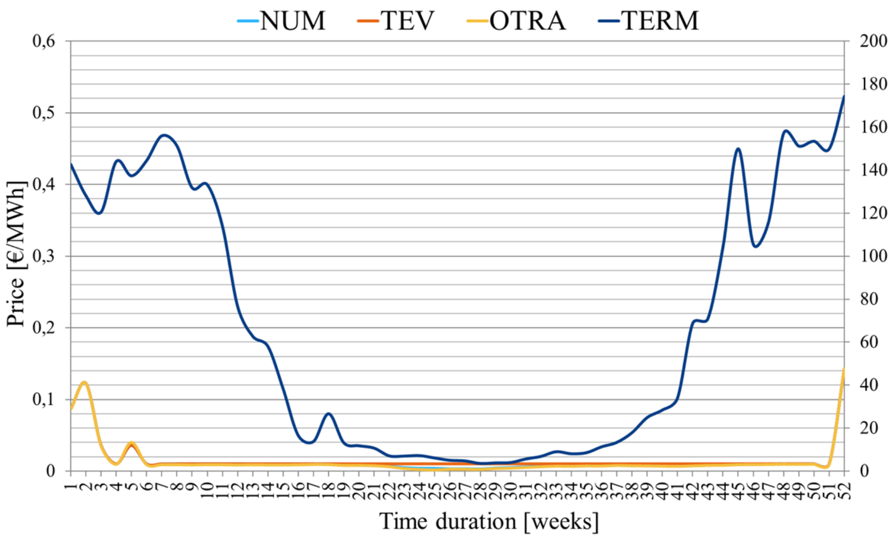


Figure 8.6: Mean power prices [€/MWh], scenario X7 and R = 320,86 MW

8.2.3 Scenario X16: Small and local

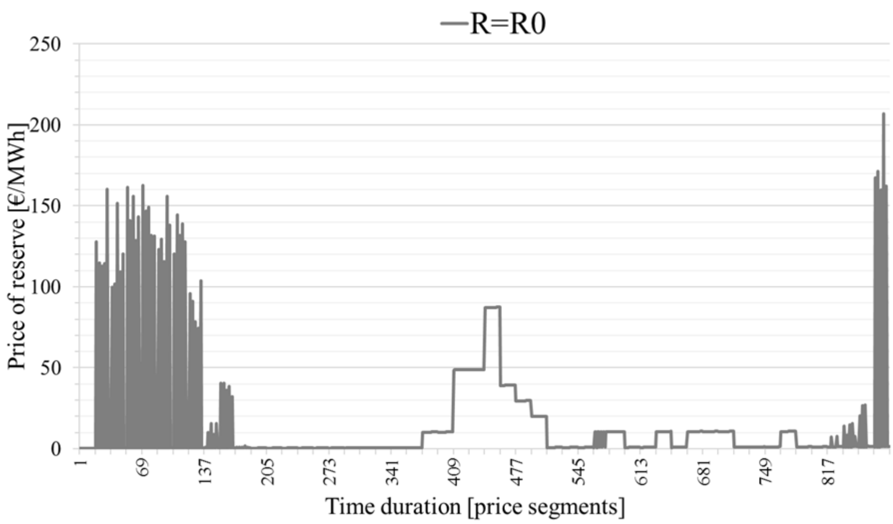


Figure 8.7: Reserve prices [€/MWh], scenario X16 and R = 316,20 MW. 17 price segments forms one week.

The dual values of the reserve requirement of R = 316,20 MW in scenario X16 are illustrated in Figure 8.7. The reserve prices are higher than in both scenario X5 and X7, and contain the brief increments of reserve price and the stable increases over longer time periods. The brief increments of the power prices are mainly found in the beginning and end of the year, week 2-10 and 49-52, and are in the area of 100-150 €/MWh. The stable increments of the reserve prices are found in the middle of the year, in the weeks 22-46. These increments are in the area of 10-90 €/MWh. The mean value of the reserve price during the year is 13,881 €/MWh, which is the highest mean reserve price of the three scenarios.

The socioeconomic surplus of scenario X16 with R = 0 MW and R = 316,20 MW = R0 are given in Table 8.5. The total SS are lower than the total SS in scenario X5 and X7. This is mainly due to lower surplus in TERM in scenario X16. The difference in total SS is 3 663 k€, 3 663 000 €, which is significantly higher than in scenario X5 and X7. A difference of 3 663 000 € equals a cost of 11 584,44 €/MW and 1,322 €/MWh of reserve. The reserve requirement resulted in decrease of surplus in NUM, TEV and TERM, while an increase of surplus in OTRA.

Table 8.5: Socioeconomic surplus [k€], SS, scenario X16 with R = 0 MW and R = 316,20 MW

	NUM	TEV	OTRA	TERM	Total
SS, R = 0 MW	1 291 571	1 151 790	561 836	35 885 425	38 890 622
SS, R = 317,36 MW	1 284 669	1 149 502	569 904	35 882 884	38 886 959

The shape and value of the power prices in scenario X6 are different than in scenario X5 and X7: The prices in NUM, TEV and OTRA does not completely coincide and are different than near zero during the major part of the inflow season. In addition, the power prices in NUM, TEV and OTRA, before and after adding the reserves, are different in shapes and values in week 1-12 and 51-52. The power power prices before and after adding the reserve requirement of 316,20 MW for scenario X16 are illustrated in Figure 8.8 and 8.9. The prices in NUM and TEV are represented by the orange graph, while OTRA are represented by the yellow and TERM by the dark blue.

The power prices in TERM are similar in shape and value as the power prices in scenario X7 and X5 in the depletion season, with an average value of 150 €/MWh. The prices are higher than scenario X7 and more similar to X5 during the inflow season after the reserve requirements are added, with a price of less than 15 €/MWh in the middle of the year, week 23-32.

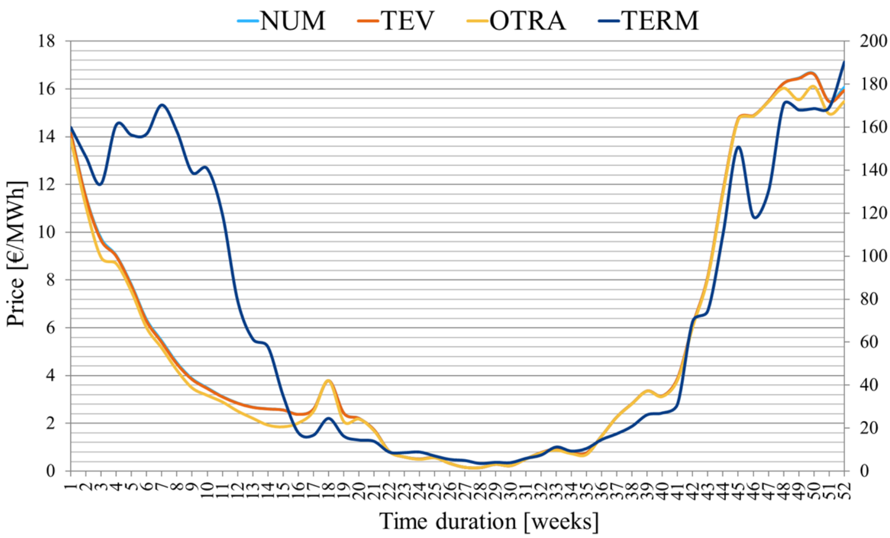


Figure 8.8: Mean, weekly power prices [€/MWh], scenario X16 and R = 0 MW

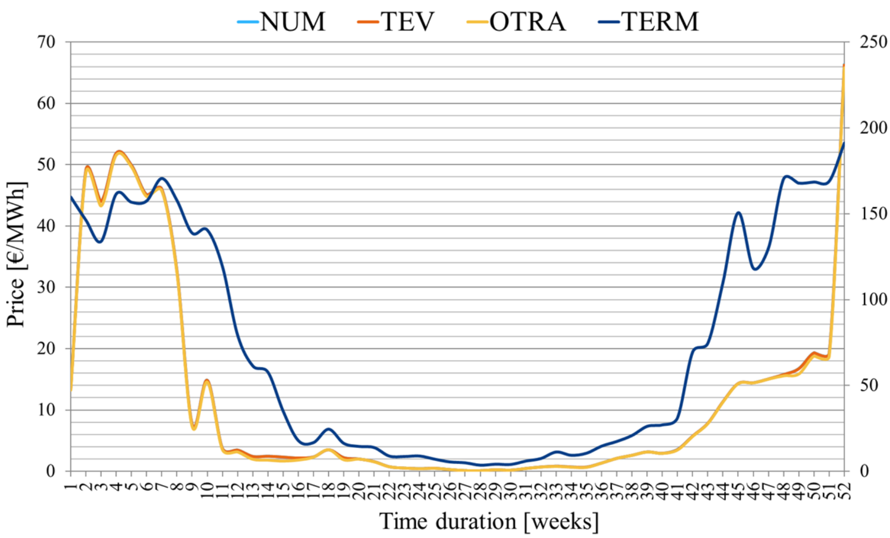


Figure 8.9: Mean power prices [€/MWh], scenario X16 and R = 316,20 MW

8.3 Discussion

The main objectives in Case I are quantifying the reserve procurement and the cost of the reserve procurement for Norway in scenarios representing 2050. The introduction of the reserve requirements had less impact on power prices than expected. Nevertheless, both dual value and change in socioeconomic surplus indicate that the introduction of reserve requirements has a price and a cost. The price and cost of the reserve requirements had different extent in the three scenarios. Table 8.6 lists the mean cost of reserves represented by the dual value of the reserve requirement and the difference in socioeconomic surplus. There are differences in the quantification of the cost of procurement of reserves in the two approaches. The dual value generally gives a higher mean value than the difference in socioeconomic surplus.

Table 8.6: Mean cost of reserve requirement [€/MWh] represented by the dual value and difference in total socioeconomic surplus with no reserve requirement (R = 0 MW) and the reserve requirement, R0, relative to the scenario

	From dual value	From difference in SS
X5	1,041	0,011
X7	4,186	0,003
X16	13,881	1,322

The scenarios include similarities, including power portfolio, characteristics of demand and value of reserve requirement. Despite their similarities, including the reserve requirement affect the power prices different; no effect on scenario X5 and X7, but a visible effect in scenario X16.

The discussion aims to enlighten the results by discussing the findings presented in the previous section.

8.3.1 Power prices

The power prices in the Norwegian nodes, NUM, TEV and OTRA are generally low in all of the scenarios. In the inflow season, week 18-41, prices are close to zero, and outside the inflow season, in the depletion season, mean prices in X5, X7 and X16 are at 12, 0,05 and 8 €/MWh. The prices are reflected by the production capacities and demand, illustrated in Table 6.8. Scenario X7, with the lowest price during the whole year, has the highest production capacity and the lowest demand in all nodes. Scenario X5 has similar production capacities but increased demand compared to X7, and X16 have the lowest production capacity and the highest demand relative to the other scenarios.

The Norwegian nodes have a surplus of power and a dominating share of hydro power production in all of the scenarios. The low prices during the inflow season reflect the strategy in the inflow season, which aim at minimizing the risk of spillage. The strategy results in low water values and allows power production despite prices close to zero. If the producers are not able to empty their reservoirs during the depletion season and the reservoir volume exceed the targeted volume at the end of the depletion season, the producers will produce power to maximize their earnings; they will produce regardless of low power prices, as the income will be higher than zero, which is their income in case of spillages. The lowest price in the system is set by the cost of flooding, which is manually or automatic set and prevent negative prices. The reservoir handling for the scenarios can be found in Appendix F.

The prices in TERM are affected by the Norwegian nodes because of the import of power from OTRA to TERM via the transmission cable L4: OTRA-TERM. The power prices in TERM are also affected by the renewable power production within TERM; the solar radiation in Denmark and Germany increases during the spring and summer. As the power from renewable energy sources are priced close to zero, the market clearing sets a lower market price in TERM during this period. The prices also vary with the energy series of the wind and solar power production, resulting in extreme values, at zero or ration cost, in the lowest and highest percentiles of the power prices for TERM. The mean prices are affected by these extreme values.

All nodes follows the same load curve; the yearly and weekly load profiles described in Section 4.2. The yearly load profile cause the demand to decrease in the spring and summer, with the lowest point in week 29. The load profile fits with the price profile of node TERM and the power prices in the Norwegian nodes in scenario X16. Due to low prices in scenario X5 and X7, conclusions can not be drawn relative to these scenarios, but generally, the prices are lowest during the time period with the lowest demand.

8.3.2 Effect from reserve requirements on the power prices

Introducing the reserve requirement had little to no effect on the power prices in scenario X5 and X7. The surplus of power generation, particularly the surplus of hydro power in the Norwegian nodes NUM, TEV and OTRA, handles the reserve procurement by increasing the hydro power production. This does not result in an increase of the power prices in any of the areas, and the prices remains low. An exception was found in scenario X7, week 52: The price in week 52 are decreased from 0,7 to 0,14 €/MWh. However, there are not sufficient changes in the prices to draw conclusions towards the effect of the reserve requirement as the prices could be affected by other elements in the simulation.

The same, minimal effect can be seen the difference of the socioeconomic surplus, where the costs of the implementation of the reserve requirements were found to be

0,011 and 0,003 €/MWh for scenario X5 and X7. Adding these cost to the price of power would results in a minimal increase of the power prices, with no visible effect in the figures representing the price of power. The increase in average power price is 0,05 €/MWh for scenario X5 and 0,0005 €/MWh for scenario X7. The dual value as price of power from scenario X5 showed an average of 1,04 €/MWh, with a trend of increasing prices from 0 to 1 €/MWh through the year. In addition, brief increments of the reserve prices could be found in the middle and end of the year. These briefs were expected to affect the prices, but looking at the power prices for the weeks including the brief variations, week 22-26, 45 and 52, no dissimilarity from scenario X5 without the reserve requirements was found. The power prices per price segment were studied to validate the findings. Similar, the reserve prices in scenario X7 in the price segments containing the steady prices of reserves at 10-50 €/MWh in week 21-28, were expected to affect the power prices. No dissimilarities could be found in this time period in the mean, weekly power prices, or the power prices per price segments.

Scenario X16 are different from scenario X5 and X7; the power prices are generally higher in the Norwegian nodes and including the reserve requirement of 316,20 MW did affect the power prices. The author wants to make the reader aware of the values of the axis in the presentation of the prices before and after introducing the reserve requirement, Figure 8.8 and 8.9.

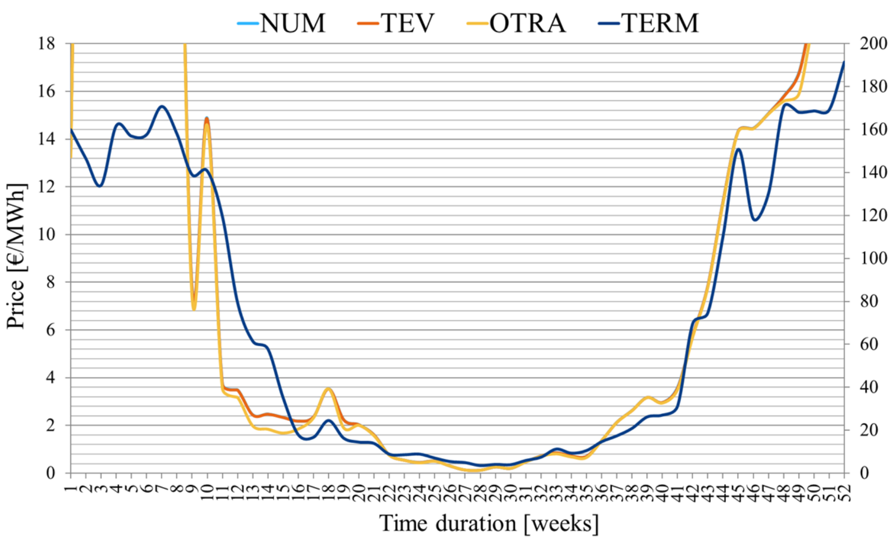


Figure 8.10: Zoomed: Mean power prices [€/MWh], scenario X16 and R = 316,20 MW

In Figure 8.10, the primary and secondary axis have been scaled to coincide with the axis in scenario X16 before introducing the reserve requirement. Figure 8.10 illustrates that the largest affects on the power price in scenario X16 is found outside the inflow season. During the inflow season, it seems like the decrease in demand in addition to the surplus and strategy of hydro power producers keeps the prices low in the Norwegian nodes after the introduction of the reserve requirement.

The mean increase in the power prices by introducing the reserve requirements is 1,94 €/MWh. Implying a linear relationship between the price/cost of reserves and the power price would imply that the power prices should increase with the price of reserves or, in the case of different price and cost of reserves, the cost of reserves the increase in SS imply. The relationships between the two (three) prices are not linear in a complex power system; increase in demand or reserve requirement can result in higher water values, which again affect the power price. The variations in the power prices may affect the exchange with other areas and result in differences prices in the Norwegian nodes. An increase in requirements for production may imply the start-up of biomass or thermal generators. In scenario X16, the Norwegian nodes hold a two biomass generators of 12,6 and 9,8 MW, but no thermal generation. The start-up costs for biomass generators are zero, but the price of fuel could potentially result in a higher cost of power from biomass. The production of power from the biomass generators in node NUM and OTRA was investigated, but the results from the simulation showed zero production in all price segments of all 50 inflow scenarios. This results leads in the direction of price sat by water values, mainly by the possibility of selling the power to a higher price if exporting it to TERM via the transmission cable between OTRA and TERM.

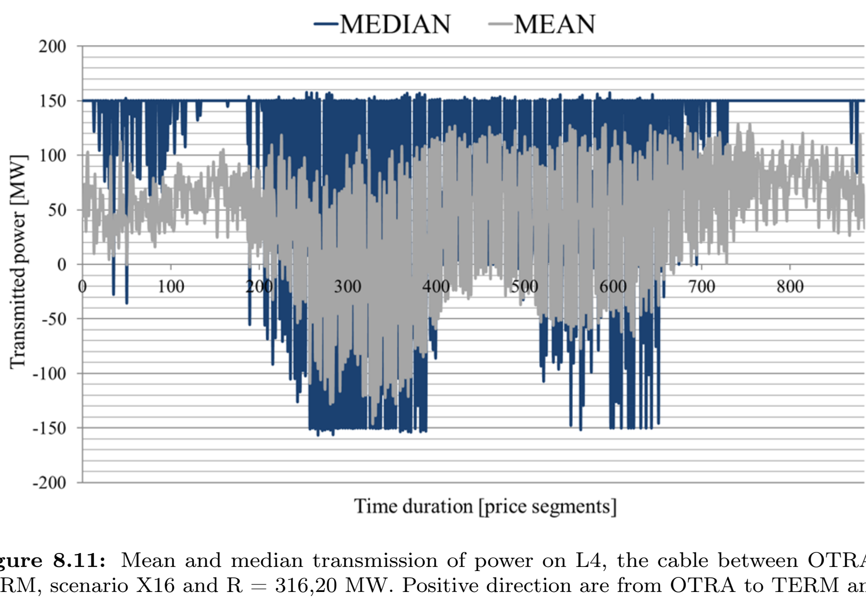


Figure 8.11: Mean and median transmission of power on L4, the cable between OTRA and TERM, scenario X16 and R = 316,20 MW. Positive direction are from OTRA to TERM and the data are given for 884 price segments, one year.

The power flow in the transmission cable L4: OTRA-TERM with R = 316,20 MW in scenario X16 are illustrated in Figure 8.11. The mean value show that the cable is used to transport an (approximate) average of 50 MW from OTRA to TERM. The mean value gives an indication of the trend in the use of the cable, supported by the median value of the exchange during the year. The use of mean values are further discussed in Section 8.3.5. The amount of use of maximum transmission capacity indicates that that the prices in OTRA are affected by the prices in TERM. Similarly, the prices in NUM and TEV are affected by the price in OTRA, and hence TERM, and each other via the transmission lines L1: NUM-TEV, L2: TEV-OTRA and L3: OTRA-NUM.

8.3.3 Reserve prices represented by dual values and difference in socioeconomic surplus

The dual value of the reserve requirement and the difference in SS do not coincide in any of the scenarios. The values obtained for the reserves and the increase in mean power prices are given in Table 8.7. The increase in mean power prices indicate that the mean reserve prices printed from the EMPS model are high, affected by the peaks in the reserve prices during the year. The differences in SS are lower and more equal to the increase of the power prices in value.

Table 8.7: Mean cost of reserve requirement [€/MWh] represented by the dual value, difference in total socioeconomic surplus with no reserve requirement (R = 0 MW) and the reserve requirement, R0, relative to the scenario and increase in power prices [€/MWh]

	From dual value	From difference in SS	Increase in power prices
X5	1,041	0,011	0,05
X7	4,186	0,003	0,0005
X16	13,881	1,322	1,94

The medians of the price of reserves are investigated to see if the value of the median reflects the prices of reserves during the year more accurate than the mean value. The median of the reserve prices are 0,73 €/MWh for scenario X5, 0,81 €/MWh for scenario X7 and 0,96 €/MWh. The median fits the values for scenario X5, as the dominating share of the reserve prices during the year were in the interval of 0-1 €/MWh. The same arguments applies for the median of X7, as the dominating share of reserve prices are in the interval of 0-1,4 €/MWh. The median of X16 does however not provide a representative image of the major parts of the values as the share of prices of reserves significantly bigger than zero, in the interval 10-150 €/MWh, are higher than the share of prices close to zero.

In theory, the dual value should increase in value with the decreasing surplus of power in the scenarios. The dual value was expected to be lowest in scenario X7, while the mean dual value indicates a higher price of reserves in scenario X7 than in X5. This is due to the steady, high price of reserves at 10-50 €/MWh in week 21-28.

8.3.4 Possibility of increasing the load i X5 and X7

The prices in scenario X5 and X7 could be manually manipulated to higher values and thus more sensitive to the adding of the reserve requirement by increasing their demand in the Norwegian nodes or increasing the transmission capacity between the nodes and allow more export to TERM. This project did however take basis in the scenarios presented in the e-Highway2050 project, and the adjustment of the demand in the Norwegian nodes was found to increase the sources of errors significantly, and was avoided.

8.3.5 Limitations and potential sources of error

The total socioeconomic surplus in the EMPS model includes producer surplus, consumer surplus, TSO surplus, losses in the system and income/cost due to change in reservoir volume. Due to the simplified power system and transmission modelling, the values for the mentioned categories forming the total socioeconomic surplus are not included in the analysis.

The socioeconomic surpluses used in the results are given as mean values for all inflow scenarios, 50 years. The inflow scenarios cover variations of dry and wet years. By including the inflow scenarios, the surplus takes the uncertainty in inflow into account. The future can however not be based on statistical data, and the inflow in the simulated scenario will remain an estimate. The variation in solar radiation and wind speed are included by energy series for 5 years based on statistical data from 2011-2015. The same problem, and hence source of error, is present in the energy series. Additionally, the series includes statistical data from a lower amount of years, providing a lower degree of stochastic values than for the inflow.

The use of mean values for the price of power and exchange are a potential source of error: the mean value takes inputs from all the inflow years and gives an average of all values as output. In the case of the exchange by the use of the cable from OTRA to TERM, the mean value tends to the value in most of the inflow scenarios, but will also we affected by the extremes values in the case of high solar radiation and dry years. When this happens, the prices will be low in TERM and high in OTRA, resulting in use of the cable in the other direction. The mean value of the exchange will therefore be used as an indication of which way the cable tend to transfer power as the median show that the cable usually transfer power at maximum capacity one of the directions. The same arguments are valid for the use of mean values as results of the power prices. In addition, the power prices are given as average of the 17 sequential price segments during one week. The argument for using the mean, weekly power prices is that the prices are not used to quantify the cost of reserves in the power system, but are used as support and to evaluate the effect the power requirements have on the power prices seen from weekly perspective.

The simplification of the power system results in few nodes and low degree of interaction with other nodes. More nodes and higher degree of interaction between them are most likely to affect the power prices and hence the cost of reserves. In 2016, Norway is connected to the Scandinavian countries [1], the Netherlands and Russia. In addition, cables to Germany and the UK are under construction. [23]

The simplification of the power system also includes simplified handling of the demand and the power generation. As discussed in the previous section, the same load profiles are used for the Norwegian nodes and TERM. In addition, no temperature profiles are used to affect the demand profiles. Battery technology are excluded from the power system scope; including batteries as very flexible demands in the system may have effected the cost of reserves and power prices. The renewable generation are included as one big power plant for each cluster included in the nodes. The EMPS model have a functionality of implementing wind power as hydro power modules [18], which may have resulted in a more accurate description of the wind power production.

The lack of calibration between the simulations and the human interference when deciding reservoir handling are potential sources of error. Optimal handling of the reservoirs and thus global optimal solution cannot be guaranteed. The argumentation for the lack of calibration between the simulations are can be found in Section 5.3.2.

8.4 Summary, Case I

The power prices are low for all scenarios due to the surplus of hydro power in the nodes. The prices are lowest in the preceding weeks of the start of the inflow season in week 18. The power portfolio and the value of the demand in the scenario affect the prices.

The reserve requirements was calculated to 317,36, 320,86 and 316,20 MW for scenario X5, X7 and X16. Introducing the reserve requirement had a price and a cost for all the scenarios, but to different extent. Introducing the R0 had no visual effect on the power prices and a small effect on the difference of the socioeconomic surplus in scenario X5 and X7. The increase in the average power prices was found to be 0,05 and 0,0005 €/MWh and the difference in total socioeconomic surplus resulted in a cost of 0,011 and 0,003 €/MWh for scenario X5 and X7. The average dual value was significantly higher with a value of 1,04 and 4,19 €/MWh.

[1] Sweden, Denmark and Finland

The introduction of the reserve requirement had a visible effect on scenario X16. Scenario X16 holds the lowest production surplus of the scenarios and the introduction of the reserve requirement had visual effect on the power prices. The largest effects were found in the time periods with high prices, in the beginning and end of the year, outside the inflow season. The power prices increased with an average of 1,94 €/MWh, the difference in total SS resulted in a cost of 1,322 €/MWh and the average reserve price was 13,88 €/MWh. The affect the reserve requirements had on the prices in scenario 16 indicates that lower surplus in a system results in higher power prices and power prices that are more sensitive to adjustments in the system. This will be further investigated in Case II.

The values of the dual value, the difference in total socioeconomic surplus and the increase in power prices do not coincide in any of the scenarios, and the reserve prices are generally significantly higher than the two other values. The basis for the values, limitations and the potential sources of errors were identified and discussed.

9 Case: Sensitivity analysis

9.1 Increasing the reserve requirement

In Case II, the reserve requirements for the scenarios are increased with multiples of the reserve requirement calculated in Case I. By increasing the reserve requirement, the sensitivity analysis covers dimensioning faults in the Norwegian power systems.

The dimensioning fault entail the greatest impact upon the power system from all fault events that have been taken into account [16]. The dimensioning faults in Norway are assumed to be 1 200 MW, and divided between the bidding zones of Norway in the following way [8]:

- NO1: 170 MW
- NO2: 600 MW
- NO3: 120 MW
- NO4: 190 MW
- NO5: 120 MW

As the master project data set includes NO1, NO2, NO3 and NO5, and the reserve requirement should be pushed against 170 MW + 600 MW + 120 MW + 120 MW = 1010 MW. The reserve requirements for the scenarios were calculated to 316,20 - 320,86 MW, and the reserve requirement will be increased with the multiples 2, 3, 4 and 10 of the calculated reserve requirement in Case I, listed in Table 8.2, to meet the number presented as dimensioning fault for the simulated system. The multiple of 10 is an extreme case of the scenarios, which represent a non-realistic situation, but are used as reference point in the sensitivity analysis.

9.2 Presentation of results

The theoretical reserve requirements, relative to the scenario and calculated in Case I, Chapter 8, are referred to as R0.

Table 9.1: Calculated reserve requirements in Case I, R0 [MW], for the Norwegian region in the scenarios

	X5	X7	X16
R0	317,36	320,86	316,20

9.2.1 Scenario X5: Large scale RES

As the reserve requirement in scenario X5 were multiplied with 2, 3, 4 and 10, the reserve prices increased, as illustrated in Figure 9.1.

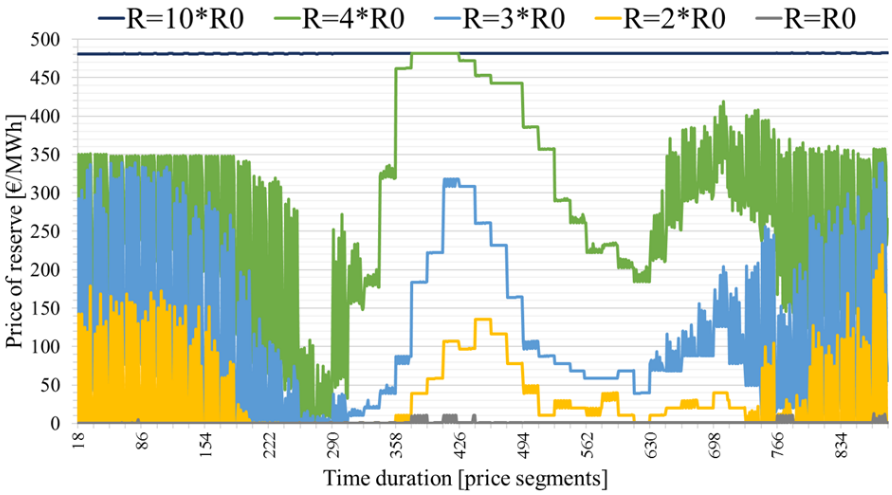


Figure 9.1: Reserve prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 317,36 MW, scenario X5. 17 price segments forms one week. The first week of the year is intentionally left out.

As the reserve requirements are increased, the prices grow to higher levels relative to no reserves. The shape of the price curve are similar in the cases of R = 1, 2, 3 and 4*R0. In all cases except 10*R0, the prices are varying in the beginning and end of the year, while they are steady in the middle of the year. The first rationing occur in the case of 4*R0, where the reserve price have steady peaks at 350 €/MWh in the weeks 1 to 11. After week 11, the reserve prices increases to values over 350 €/MWh, with a top with a value of 480-482 €/MWh in price segment 392-443. In the case of 10*R0, the system are saturated, with a steady reserve price at 480-482 €/MWh during the whole year.

The total socioeconomic surplus for the system, the difference in SS relative to no reserves and the cost of reserves based on the difference in SS are presented in Table 9.2. The values of the total SS are decreasing with increasing R. The socioeconomic surplus decreases with 31 k€ in the first increase of R, and obtain a larger value of the difference when increasing the reserve requirement to 2, 3 and 4*R0. The cost of reserves follows the trend of the difference and increases from 0,011 to 24,35 €/MWh in the cases of increased R. The cost of reserves decreases from 24,35 €/MWh for 4*R0 to 17,11 €/MWh for 10*R0.

Table 9.2: The total socioeconomic surplus [k€], the difference in total socioeconomic surplus [k€] relative to no reserve requirement (R = 0 MW) and the cost of reserves [€/MWh] for simulations in X5 with different values of reserve requirement, R

	Total socioeconomic surplus	Difference in total surplus	Cost of reserves
R = 0	51 584 712	-	-
R = 1*R0	51 584 681	31	0,011
R = 2*R0	51 574 806	9 906	1,78
R = 3*R0	51 504 781	79 931	9,58
R = 4*R0	51 313 959	270 753	24,35
R = 10*R0	51 108 862	475 850	17,11

The corresponding power prices of the cases of increase reserve requirement are illustrated in Figure 9.2. The power prices show that the prices of power increases with increased reserve requirement in the time period with prices higher than (close to) zero. The prices are low in the middle of the year, but the number of weeks with prices close to zero decreases with the increased R. In the case of no reserve requirement and R0, the power prices were close to zero during week 7 to 44, while the interval decreases to week 21-31 in the case of 10*R0.

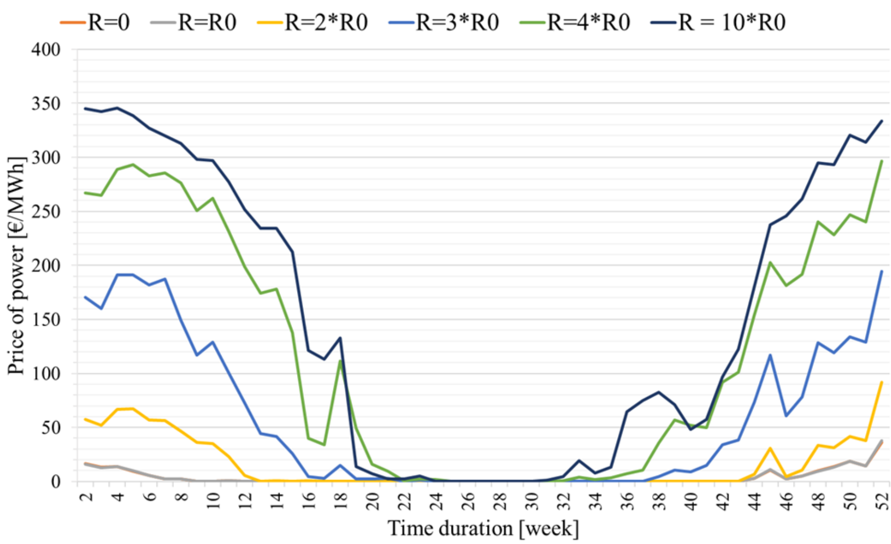


Figure 9.2: Trend in the mean, weekly power prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 317,36 MW, scenario X5. The first week of the year is intentionally left out.

9.2.2 Scenario X7: 100% RES

The reserve prices are presented in Figure 9.3. The prices of reserves in scenario X7 share many similarities to the prices of reserves for scenario X5: The prices of reserves increases with increased R, have large and fast variations in the reserve prices outside the inflow season and steady, longer lasting prices during the inflow season. The saturation price of 480-482 €/MWh are in both scenarios obtained in the middle of the year for 4*R0. For 10*R0 are the reserve prices equal to the saturation price in all price segments during the year.

The prices of reserves are higher than for scenario X5 inside the inflow season and lower outside the inflow season. This results in a longer interval of saturating price when 4*R0 for scenario X7 than X5, and that the prices in the beginning of the year for 4*R0 does not reach the rationing price of 350 €/MWh as in scenario X5.

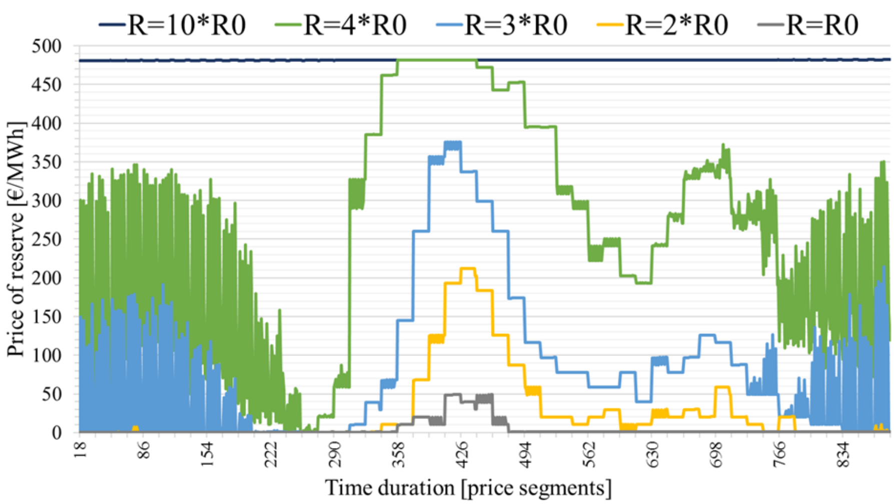


Figure 9.3: Reserve prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 320,86 MW, scenario X7. 17 price segments forms one week. The first week of the year is intentionally left out.

The characteristics of the socioeconomic surplus in scenario X7 are presented in Table 9.3. The trend of decreasing surplus is similar to the trend seen in scenario X5, with a decrease of 7 in the first increase of R, and a increasing value of the difference when the reserve requirement are increased. The change in socioeconomic surplus are lower than in scenario X5and the cost of reserves are calculated to values in the interval of 0,003 to 8,18 €/MWh. The maximum cost of reserve is found in the case of 4*R0 as the cost of reserves are 6,65 €/MWh in the case of 10*R0.

Table 9.3: The total socioeconomic surplus [k€], the difference in total socioeconomic surplus [k€] relative to no reserve requirement (R = 0 MW) and the cost of reserves [€/MWh] for simulations in X7 with different values of reserve requirement, R

	Total socioeconomic surplus	Difference in total surplus	Cost of reserves
R = 0	51 186 219	-	-
R = 1*R0	51 186 212	7	0,003
R = 2*R0	51 186 191	28	0,005
R = 3*R0	51 175 331	10 888	1,29
R = 4*R0	51 094 225	91 994	8,18
R = 10*R0	50 999 166	187 053	6,65

The prices of power for scenario X7 are presented in Figure 9.4. The prices are high in the beginning and end of the year, with prices close to zero in the middle of the year. The prices are lower than in scenario X5 and have a longer time period with prices close to zero. Prices are close to zero during the whole year for R = 0, 1 and 2*R0. When R is increased to 3*R0, prices increases to 50-75 €/MWh during the weeks 2-13 and 44-52, but are still close to zero during the rest of the year. When the reserve requirement are increased to 4*R0 and 10*R0, the time period with prices close to zero are decreased with 11 and 15 weeks.

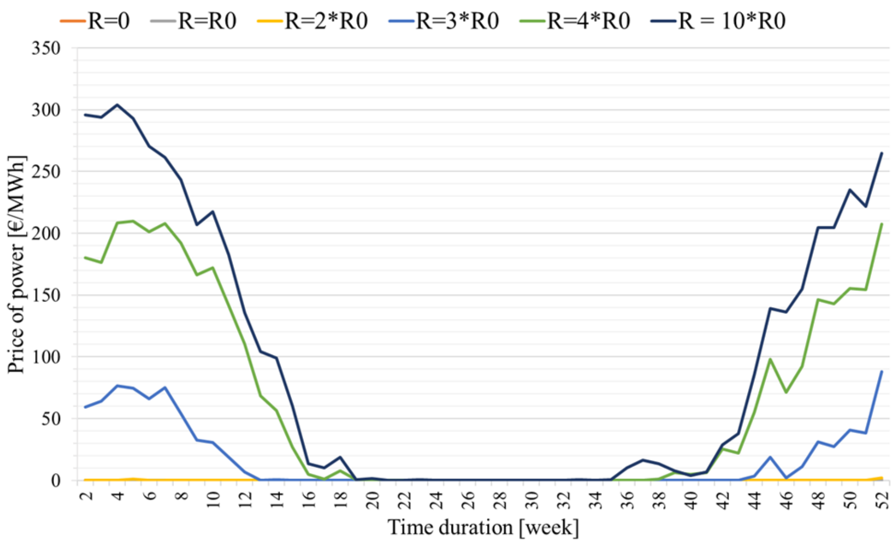


Figure 9.4: Trend in the mean, weekly power prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 320,86 MW, scenario X7. The first week of the year is intentionally left out.

9.2.3 Scenario X16: Small and local

The prices of the reserves are presented in Figure 9.5. The dual values of the reserve restriction are higher outside the inflow season compared to the two, previous scenarios, X5 and X7. The prices have rapid and large variations in the beginning and end of the year and steady price levels in the inflow season. The rationing price of 350 €/MWh are obtained for 3*R0 week 2-11 and week 25, while the saturation price of 480-482 €/MWh are obtained for 4*R0 in week 23-26 and during the whole year for 10*R0.

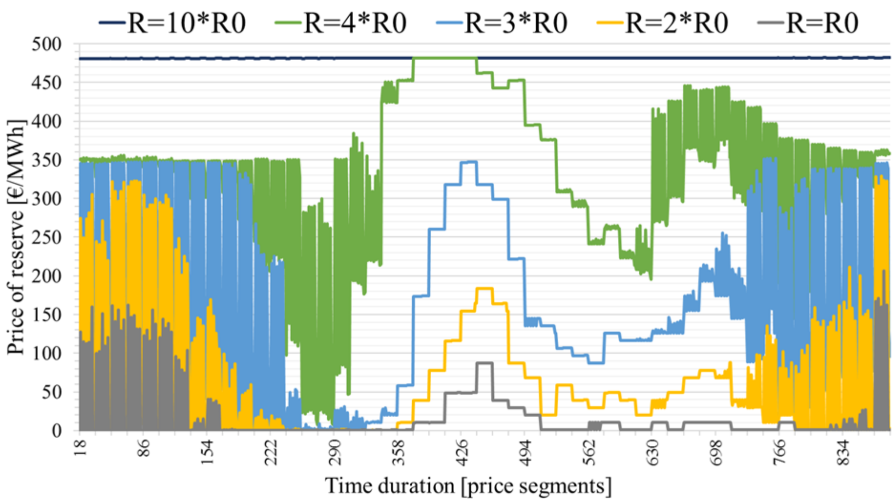


Figure 9.5: Reserve prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 316,20 MW, scenario X16. 17 price segments forms one week. The first week of the year is intentionally left out.

Table 9.4: The total socioeconomic surplus [k€], the difference in total socioeconomic surplus [k€] relative to no reserve requirement (R = 0 MW) and the cost of reserves [€/MWh] for simulations in X16 with different values of reserve requirement, R

	Total socioeconomic surplus	Difference in total surplus	Cost of reserves
R = 0	38 890 662	-	-
R = 1*R0	38 886 959	3 703	1,34
R = 2*R0	38 858 300	32 362	5,84
R = 3*R0	38 747 178	143 484	17,27
R = 4*R0	38 470 994	419 668	37,88
R = 10*R0	38 259 450	631 212	22,79

The characteristics of the socioeconomic surplus, listed in Table 9.4, confirm the trend of decreasing surplus with increasing reserve requirement, as seen in the previous scenarios. The growth in the difference of the surplus is rapid, with corresponding rapidly growing cost of reserves. The highest cost of reserves are found when 4*R0, with a price of 37,88 €/MWh.

The power prices corresponding to the increase of R are found in Figure 9.6. The prices increases with increasing R, with the exception of week 19-22, when the prices for 4*R0 are higher than the prices for 10*R0. The prices are close to zero in the middle of the year, similar to scenario X5 and X7.

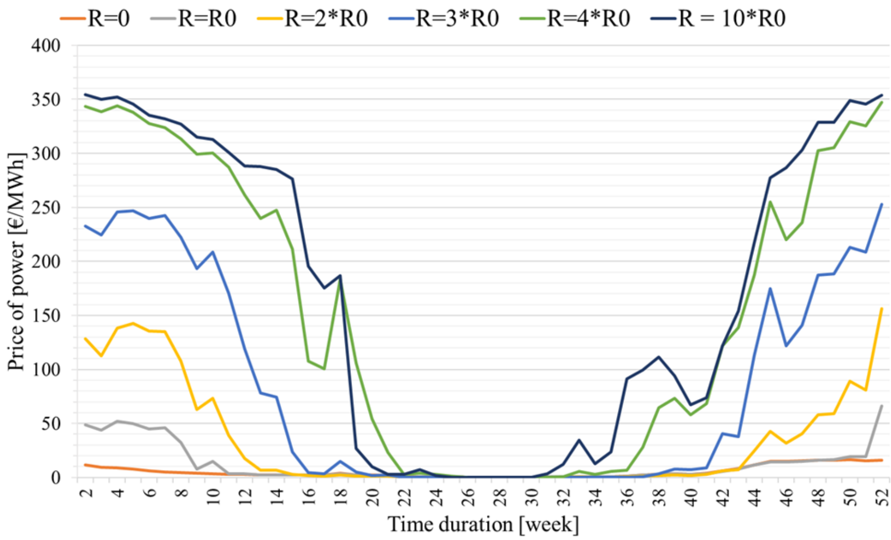


Figure 9.6: Trend in the mean, weekly power prices [€/MWh] when increasing the reserve requirement by a multiple of R0 = 316,20 MW, scenario X16. The first week of the year is intentionally left out.

9.3 Discussion

9.3.1 The prices of reserves (dual values)

The dual values of the reserve requirements generally increase with increased R, have fast, large variations outside the inflow season and steady, longer lasting price steps within the inflow season for all scenarios. A factor affecting the large variation in the prices of reserves may be the large variations in wind and solar power production. The variations of wind power production are illustrated in Figure 9.7. The power generated by wind is rapidly varying, and may induce corresponding rapidly needs for reserves, reflected in the reserve prices.

The prices for reserves are notable higher in the middle of the year. A factor can be found in the energy series for wind power production. When investigating the trend of the produced energy during the five years used as input for the wind energy, a lower aggregated wind power production can be found in the Norwegian nodes during the middle of the year, middle of April to the start of September. NUM, TEV and OTRA have a aggregated wind capacity at 37,4, 32,4 and 14,9 % of total production capacity in X5, X7 and X16. Additionally, the precipitation are lower in the middle of the summer, which can affect the production of power from ROR [1], and the producers with hydro reservoirs are focused on filling their reservoirs, resulting in less bypass and hence ROR production. The reduced production may affect the market and hence the prices of reserves during the relevant time period.

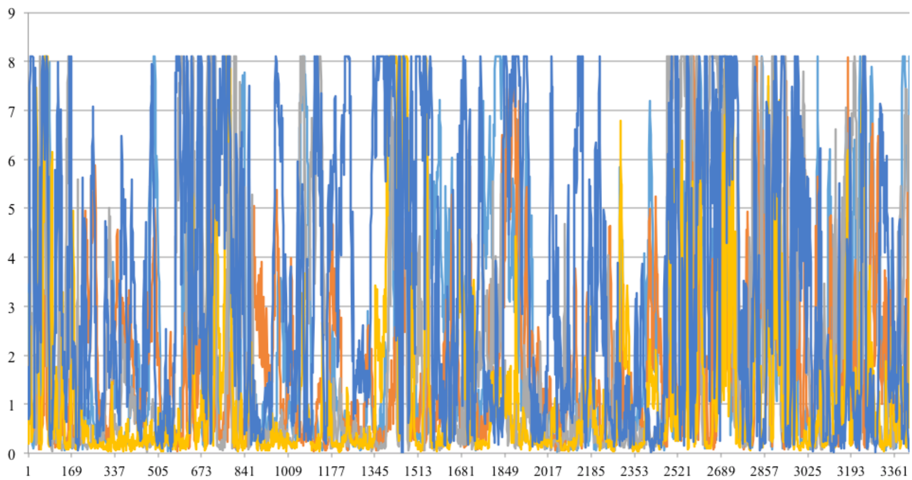


Figure 9.7: Cutting of energy series [MWh/1 MW installed capacity] for wind power in clusters representing the Norwegian nodes. The data are given per hour for week 1 to 20 in year 2013 and obtained from Ingeborg Graabak, SINTEF Energy.

For scenario X5 and X16, a steady reserve price of 350 €/MWh, referred to as one of the rationing prices, are obtained in the beginning of the year when 4*R0 in scenario X5 and 3*R0 in X16. This is the rationing price in OTRA, which is lowest rationing price in the system, ref. Table 4.6. The rationing cost of NUM and TEV, at 362 and 445 €/MWh, can be found in the steady prices in the middle of the year. The system is saturated in the weeks with highest reserve prices for 4*R0 and for all time periods when 10*R0 in all of the scenarios. The saturation price is at 480-482 €/MWh and is the result of the average over all 50 inflow years with a mix of the highest ration price, 445 €/MWh, in the case of the wet years and high inflow and price of not fulfilling the reserve requirement, 500 €/MWh, in the other years. As the same inflow years are used for the three scenarios, the amount of wet, normal and dry years are the same, and hence the saturation price is the same for

[1] Run of river

the scenarios. Some of the higher prices in the case of 4*R0 are in between values of 445 and 480 €/MWh which, similar to the case of 10*R0, are the results of an average of the 50 inflow years, but with a higher amount of years with reserve price equal to 445 €/MWh.

9.3.2 Trends in the socioeconomic surplus

Table 9.5 lists the total socioeconomic surplus. For all scenarios, the SS decreases when the reserve requirements, R, are increased.

Table 9.5: Total socioeconomic surplus [k€] for simulations with different values of reserve requirement, R

	X5	X7	X16
R = 0	51 584 712	51 186 219	38 890 662
R = 1*R0	51 584 681	51 186 212	38 886 959
R = 2*R0	51 574 806	51 186 191	38 858 300
R = 3*R0	51 504 781	51 175 331	38 747 178
R = 4*R0	51 313 959	51 094 225	38 470 994
R = 10*R0	51 108 862	50 999 166	38 259 450

The total SS are highest in scenario X5 and lowest in scenario X16. If excluding scenario X7, it may appear to be a link between the level of surplus of production capacity in the system and the value of the total socioeconomic surplus. When including scenario X7, the theory has to be discarded, as scenario X7 has a higher surplus and a lower value of surplus than scenario X5. The argument seems however to be valid for the first steps when increasing the reserve requirement in the difference of the surplus: The difference of the total SS are largest and has the fastest rate of growth in the scenario with the lowest surplus of production, scenario X16, and lowest and has the slowest rate of growth in scenario X7, which holds the highest production surplus. The difference of total SS are listed for all scenarios in Table 9.6 and the corresponding cost of reserves are plotted in Figure 9.8.

Table 9.6: Difference in total socioeconomic surplus [k€] relative to no reserve requirement (R = 0 MW) for simulations with different values of reserve requirement, R

	X5	X7	X16
R = 1*R0	31	7	3 703
R = 2*R0	9 906	28	32 362
R = 3*R0	79 931	10 888	143 484
R = 4*R0	270 753	91 994	419 668
R = 10*R0	475 850	187 053	631 212

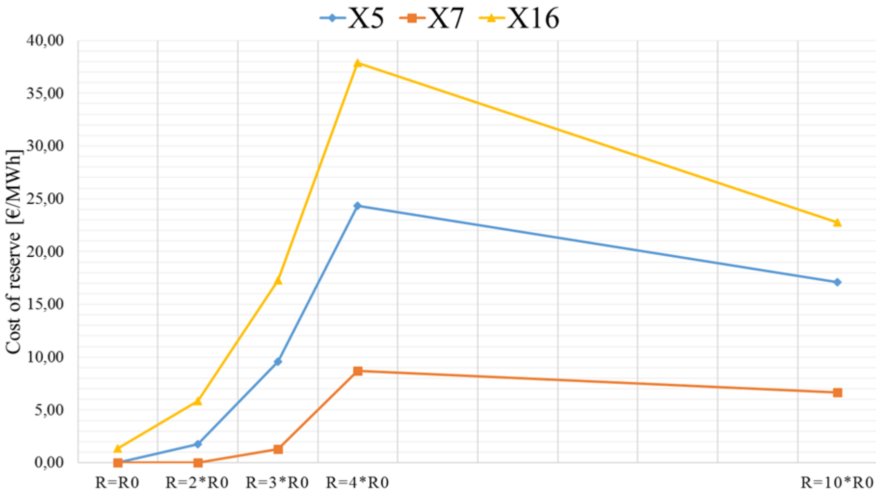


Figure 9.8: The cost of reserve [€/MWh] for simulations with different values of reserve requirement, R

The cost of reserves have an increasing trend when R increases from 1 to 4*R0 in all of the scenarios. The steepest trend can be sees for scenario X16, with the lowest amount of production surplus. The cost of reserves decreases from R = 4 to 10*R0 in all of the scenarios. This can be explained by the formula used to calculate the cost of reserves with basis in the difference of SS and the trend of reserve prices discussed in the previous subsection: As the reserve requirement increases, the price/cost of reserve increases. But, at a certain value of the reserve requirement R, the cost of reserve reaches a maximum level; the saturation price of the system. The price of increasing the reserve with one unit will be the same for all R higher than the reserve requirement in this point. The costs of reserves are found from the difference in surplus. When the system is saturated, the difference in surplus will decent to approximately zero. As the value of the reserve requirement increase, but the difference in surplus is constant, the cost of reserves will decrease with increasing amount of reserve requirement after the point of saturation.

9.3.3 Effect on the power prices

The effect of increased reserve requirements on the power prices can be seen in the weeks with the highest prices of power. The weeks with the highest prices of power are generally in the beginning and end of the year, with varying extend relative to scenario and value of reserve requirement. As expected, scenario X7 has the lowest prices of power for all R, as the scenario holds the biggest surplus of power. The prices in X7 are not affected by the reserve requirement when R = 1 or 2*R0, but have an increase of 75 €/MWh during the time periods with the highest prices during the year when 3*R0. Scenario X16 has the highest prices of power and are affected by R for all values of R. In contrast to X7, X16 have the lowest surplus of power, and were expected to have the highest power prices in the time periods with the highest prices based on Case I, which indicated that lower surplus in a system resulted in higher power prices and power prices that are more sensitive to adjustments in the system. Scenario X5 have lower prices of power than scenario X16, but have similar values to X16 in the case of 10*R0.

The increase of reserves did not affect the prices in the time periods with the lowest power prices other than decrease the time period of which the prices was close to zero. The power prices are still close to zero at their lowest level for all scenarios and all R. This was discussed in Case I, where the increments in reserve prices where expected to affect the power prices in the corresponding time periods. Similar findings were reported in a previous testing of the reserve application in the EMPS model [13]; it was found that adding reserve requirements to a system already including start-up costs increased the power prices in the time periods with the highest power prices and did not affect power prices in the time periods with the lowest power prices relative to the simulations without reserve requirements. The findings in the report [13] are explained with regular running of generators in compartment to sudden start and stops which are adding costs and hence increase the power price.

The affect the load curve has on the power prices was discussed in Case I. As all of the scenarios follows the same load curve, the yearly and weekly load profiles described in Section 4.2. The shape of the load curve can be recognized in the shape of the power prices: The shape from the yearly load curve is bent and stretched, but the peaks can be recognized in the power prices for the scenarios with different reserve requirements. The shape of the yearly load curve are most visible for the cases of R = 3, 4 and 10*R0 in scenario X5 and X16. The investigation is valid for the average of the power prices in the Norwegian nodes only, as the prices in the individual nodes in the area representing Norway and the prices in TERM was not included in Case II.

9.3.4 Limitations and possible sources of error

All of the simulations presented in Case I and II have been run with two versions of Samtap. Samtap needed to be upgraded to a newer version to include the functionality of printing the dual values of the reserve restriction and hence the prices of reserves. The difference in socioeconomic surplus from the simulations with the initial, and oldest, version of Samtap are given in Table 9.7.

Table 9.7: Difference in total socioeconomic surplus [k€] relative to no reserve requirement (R = 0 MW) for simulations with different values of reserve requirement, R, using an old version of Samtap

	X5	X7	X16
R = 1*R0	18	4	353
R = 2*R0	1 056	25	3 059
R = 3*R0	6 290	888	11 550
R = 4*R0	17 681	6 607	22 521
R = 10*R0	25 500	12 460	26 274

The values used in the analysis are presented in Section 9.2 and are obtained from the updated version of Samtap. Comparing the numbers of difference in total socioeconomic surplus obtained from the two versions of Samtap, significantly higher numbers are registered by the updated version of Samtap. The results indicate that the version of software used may affect the results of the analysis in terms of exact values, but the trends where the same in the two versions.

The reserve and power prices in the first week in all scenarios and for all reserve requirements are low relative to the prices during the rest of the year. The prices have been checked against the output data directly exported from the EMPS model: The prices in the first 17th price segments are significantly lower than the prices in the 18th and forward price segments for all inflow years and in all scenarios. The author has not succeeded in finding any indications of why this is. Hence, the first week are excluded from the analysis.

The limitations and sources of errors found in Case I are valid for Case II and can be found in Section 8.3.

9.4 Summary, Case II

The reserve requirement was increased with 2, 3, 4 and 10 times of the theoretical reserve requirement calculated in Case I.

The dual values of the reserve requirements generally increased with increased R, have fast, large variations in the price outside the inflow season and high, steady and longer lasting price steps in the middle of the year for all scenarios. The shape of the curve is kept relative to the scenario, while the values are increases. Renewable power generation was identified as a possible source for the variations in the reserve prices. Lower aggregated wind power production and lower participation and hence power production from ROR in the middle of the year was identified as factors affecting the reserve prices during the time period. The rationing prices in the system were localized in the curves of the reserve prices. The system was saturated in the middle of the year for R = 4*R0 and during the whole year for 10*R0 for all scenarios. The saturation price in the system is the average of the highest ration price, at 445 €/MWh, and the price for not fulfil the reserve requirement, at 500 €/MWh, for the 50 inflow scenarios.

The value of the socioeconomic surplus could not be connected to the amount of production surplus in the scenarios as the total socioeconomic surplus were higher in scenario X5 than in X7, while X7 holds the biggest production surplus. The difference in SS did seem to be affected by the level of production surplus in the scenario; the scenario with the lowest production surplus had the largest differences and the fastest rate of growth in differences in SS, while the scenario with the highest production surplus had the lowest of both values. The difference in socioeconomic surplus are not valid for calculating the cost of reserves for R > 4*R0, as the system is saturated.

The increase of the reserve requirements had effect on the power prices in the time periods with the highest prices of power, but did not affect the prices in the time periods with the lowest prices of power other than decrease the time period of which the prices was close to zero. Similar findings are found in previous testing of the reserve application in the EMPS model [13]. The shape of the yearly load curve was recognized in the shape of the power prices in all of the scenarios, and was most visible when R is 3, 4 and 10*R0. The findings are valid for the average of the power prices in the Norwegian nodes only, as the prices in the individual nodes in the area representing Norway and the prices in TERM was not included in the analysis.

Limitations and the potential sources of errors were identified and discussed.

10 Concluding remarks

The theoretical reserve requirements was calculated to 317,36, 320,86 and 316,20 MW for scenario X5, X7 and X16 in Case I. Introducing the reserve requirement in the data sets had a price and a cost for all scenarios, but to different extent. The prices in NUM, TEV and OTRA are low during the inflow season, and the surplus of power, the dominating share of hydro and the strategy in the inflow season were identified as factors contributing to the low prices. In addition, the increased solar power production in TERM in the middle of the year may affect the prices in the Norwegian nodes. Introducing the reserve requirement had no visual effect on the power prices and a small effect on the difference of the socioeconomic surplus in scenario X5 and X7 while it had a visible and significant effect in scenario X16. The biggest effects on the power prices were found in the time periods with high prices, in the beginning and end of the year. The main findings of Case I are summarized in Table 10.1: The three values all represent the price/cost of reserves, but by different basis.

Table 10.1: Mean cost of reserve requirement [€/MWh] represented by the dual value of the reserve restriction, difference in total socioeconomic surplus and increase in power prices

	From dual value	From difference in SS	Increase in power prices
X5	1,041	0,011	0,05
X7	4,186	0,003	0,0005
X16	13,881	1,322	1,94

None of the values used to describe the effect by introducing the reserve requirement coincide. The reserve prices are higher than the two other values, and are effected by the extreme values during the year, visible in scenario X7 where the mean value of the reserve prices are affected by peaks in small time periods of the year. The cost from difference in socioeconomic surplus and the increase in power prices are more similar in terms of values.

The reserve requirement was increased with 2, 3, 4 and 10 times of the theoretical reserve requirement calculated in Case I, referred to as R0, in Case II. The dual values of the reserve requirements generally increased with increased reserve requirements, had fast, large variations in the price outside the inflow season and high, steady and longer lasting price steps in the middle of the year in all scenarios. Renewable power generation was identified as a factor contributing to the variations in the reserve prices and affecting the reserve prices during the time period with high, steady and longer lasting prices. The shape of the curve was kept, relative to the scenario, while the values increased with increased reserve requirement. The saturation price in the system was the average of the highest ration price, at 445 €/MWh, and the price for not fulfil the reserve requirement, at 500 €/MWh, for the 50 inflow scenarios.

The difference in socioeconomic was affected by the level of production surplus in the scenario; the scenario with the lowest production surplus had the largest differences and the fastest rate of growth in differences in socioeconomic surplus between R = 1 and 4*R0. The increase of the reserve requirements had effect on the power prices in the time periods with the highest prices of power, but did not affect the prices in the time periods with the lowest prices of power other than decrease the time period of which the prices was close to zero. The shape of the yearly load curve was recognized in the shape of the power prices in all of the scenarios, and was most visible when the reserve requirement was set to 3, 4 and 10*R0.

In all of the scenarios and both of the cases, the main sources of errors was identified. They were found to be the use of mean values aggregated over the 50 inflow years and over weekly time periods, the simplification of the power system, including few nodes, low degree of interconnection, simplified demand profile, the version of software and the lack of calibration between the simulations.

11 Suggestions for further work

The recommended further work are divided into two parts: The first part treat the extension of the modelled power system, with focus on increasing the level of details, while the second part treats the extent of the analysis.

1: Extension of the modelled power system

- Increasing the number of nodes in the Norwegian area to include all bidding zones in Norway.
- Add nodes and transmission lines for and between the countries directly connected to the Norwegian power system [1], including Sweden, Denmark, Finland, the UK, Germany and the Netherlands.
- Adapt demand profiles to each of the countries or nodes, including temperature dependency.
- Model wind and solar power production as hydro modules to increase the accuracy of the renewable production.
- Use non-scaled e-Highway data for modelling the system, including e-Highway hydro power production.
- Include, if possible, start- and shutdown time for thermal generators.
- Include the time resolution for the reserve requirements, i.e. for each price segment, and divide the reserve requirements into up- and down regulation. In the long run, the reserves can be divided into primary, secondary and tertiary reserves.

A more detailed power system model will provide a more accurate image of the future power system and prices. As a result, the values can more easily be compared with real-time values of the prices.

2: Analysis

- Include a scenario that contain battery technology. Batteries can be modelled as very flexible demand in the EMPS model.
- Simulate the cases of reserve requirements between 4 and 10*R0 to provide a more precise image of the trend for reserve prices, the socioeconomic surplus and the power prices.

[1] In 2016 and the cables under construction [23]

- Increase the range of the reserve requirement to exceed 10*R0 to investigate when the reserve prices equals the cost for not fulfilling the reserve requirement, 500 €/MWh, for all price segments.
- Investigate how the handling of hydro in the reservoirs are affected by the introduction of the reserve requirements, as the EMPS model handles detailed hydro power systems.

By extending the sensitivity analysis, the trends and findings presented in the master project can be validated and hence obtain increased reliability, or contradict the results obtained in the master project.

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A The Norwegian power system and portfolio

This appendix are taken from the authors specialization project, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1], as specified in Section 1.3.

The Norwegian power system is part of the Nordic, synchronous power system [1]. The NPS consists of the electrical power systems in Norway, Sweden, Finland and the eastern part of Denmark, Sjaelland. [23]

Figure A.1: The Nordic, Synchronous Power System

Hydro, thermal and nuclear power production are the main generation types in the Nordic power system, with a dominating share of hydro. Nuclear power production provides the base load in the system and is running continuous through the year. Thermal and hydro are used to cover the rest of the base load and the variations in consumption and production from RES. The generation from renewable energy sources will vary with weather conditions and unknown before real time, but can be predicted through weather forecasts. Table A.1 provides numerical values for the generating capacity of the Nordic countries. In the Table, Thermal* includes biomass and fossil fuels.

[1] A synchronous power system is a grid that operates at synchronous frequency and is electrically tied together during normal operation [23]

Table A.1: Net generation capacity in the Nordic countries [MW]. The data are provided by ENTSO-E and valid for 2015-12-31 [15]

Country	Hydro	Thermal*	Nuclear	Wind	Solar	Others	Total
Norway	31 200	1 632	0	860	0	0	33 692
Sweden	16 184	7 479	9 714	6 029	104	0	39 951
Finland	3 263	10 339	2 752	1 082	0	245	17 681
Denmark	7	8 050	0	5 082	781	2	13 922

Norway has a net generation capacity share of hydropower of over 92 percent [15]. The hydropower production is fuelled from run-of-river and hydro reservoirs. Therefore, the production strongly depends on the inflow in rivers and reservoirs. As the inflow is badly aligned with the demand profile in Norway [14], hydro reservoirs are important tools to be able to produce electricity throughout the whole year. Figure A.2 [14] illustrates that the inflow is lowest during the winter, when the precipitation comes as snow, and highest during summer when the snow melts. The demand in Norway strongly depends on temperature because electricity is used for space heating, and the use is highest during the winter.

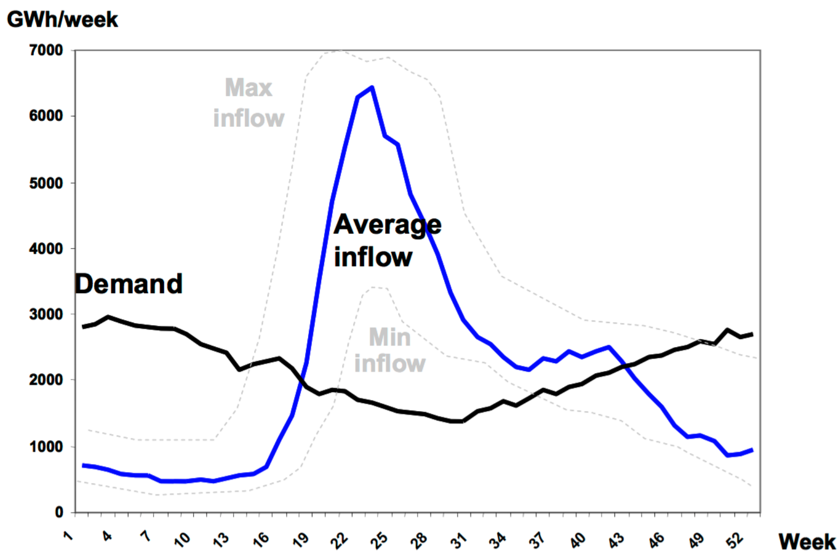

Figure A.2: Inflow versus demand in Norway during one year [14]

The inflow variation is the major source of uncertainty for the future production of power in Norway. Average hydro production during one year can vary between 95 and 140 TWh, depending on if it is a dry or wet year [14]. This is illustrated in Figure A.2 with the maximum, average and minimum inflow curves.

B Procurement of reserves in Norway

This appendix are taken from the authors specialization project, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1], as specified in Section 1.3.

B.1 The Nordic power market

This section provides an overview of the structure of the Norwegian power market. This structure is referred to as the structure of the *Nordic* power market, as the Nordic power system are closely linked and are participating in common markets (excluded the balancing markets). A more detailed explanation of the power market structure are provided in the specialization project of the author [1].

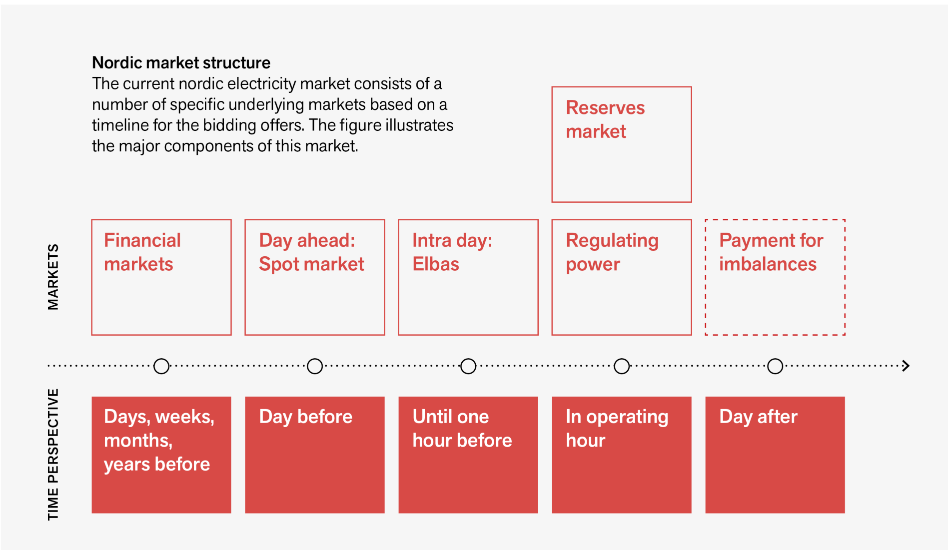

Figure B.1: Overview of the Nordic power market structure [1]

The Nordic power market consist of several sub markets in sequence, showed in Figure B.1. The goal of the power markets are to provide platforms for buying and selling power and let the players adjust their positions in the power market to make the power delivery in real time as close to scheduled values as possible.

The financial market is a contract market for trading contracts for future power delivery, called bilateral contracts. *The day-ahead market*, DAM, is the main arena for trading power and contains the biggest traded volumes of power. The market offers the opportunity to trade the power the day before the physical delivery, allowing producers and consumer to plan and schedule their production and consume. Members of the DAM, producers and consumers, can participate by submitting bids. The bid has to specify type of bid, price and quantity for the hours of the next day [2]. After the market closes the bids are gathered into separate curves for producers and consumers. The clearing of the market is illustrated in Figure B.2: By comparing the bid curves for producing and consuming power, the price and quantity of power traded for each hour of the next day are decided by the point of intersection. The players with bids on the left side of the point of intersection gets to trade their power to the market price for the given hour.

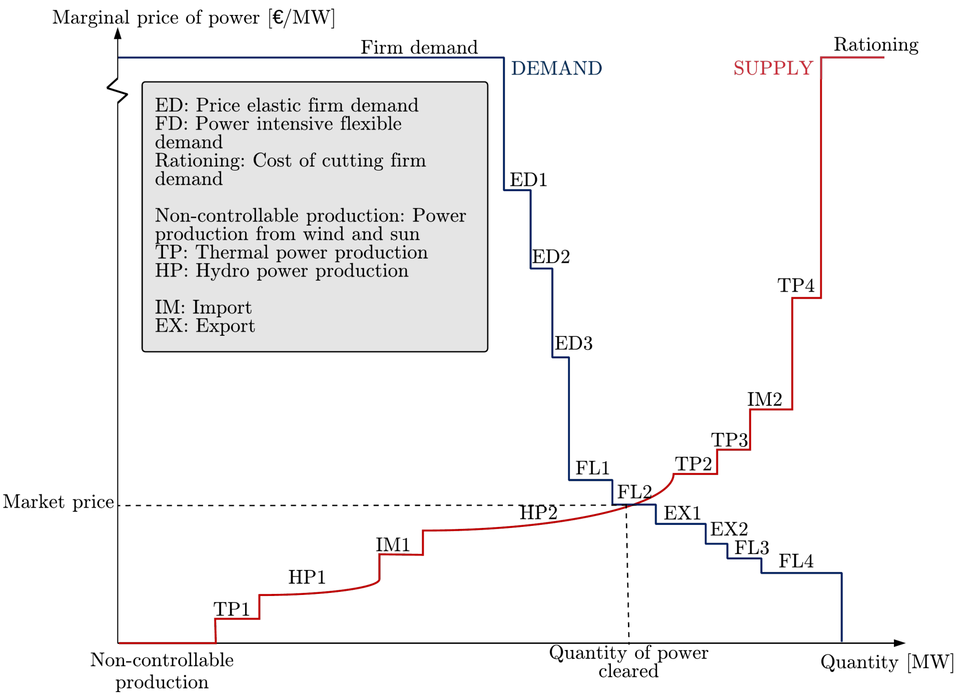

Figure B.2: Market clearing, Day-Ahead Market [19]

After the DAM closes and publishes the market clearing, *the intraday market* opens. The IDM let the players adjust their positions in the power market up to one hour before real time. The purpose of this market is to let the participants take care of imbalances in their production or consumption closer to real time, making the power delivery in real time as balanced as possible [2]. After the IDM closes, *the Balancing markets* are used to balance the power system. The balancing markets are more detailed described in the next subsection.

B.2 The Norwegian balancing markets

The Balancing markets are the platform for trade of balancing services, also named reserves. Balancing services includes the primary, secondary and tertiary reserves. They are reserves of active power and ensure reserve capacity, power, and reserve energy, power over time: They include both having reserve capacity at hand to ensure the system quality and balancing the energy over time in real time operation.

Activation of reserves

Figure B.3 [2] illustrates the activation of the reserves. The primary, secondary and tertiary reserves are activated in sequence to restore the frequency of the power system to its nominal value during an imbalance of power. The primary and secondary reserves are automatically activated when the frequency is outside sat limits. Because of this, primary and secondary reserves are "spinning reserves", which means that the generators providing these services are in operation when they are signalled for changing production output. The primary reserves are used to stop deviations in the frequency by stabilizing it. The secondary reserves takes over if the fault exceeds a couple of minutes, and release the primary reserves in case of new imbalances. The secondary reserves starts to restore the frequency back to its nominal value, 50 Hz. The tertiary reserves are activated in case the imbalance lasts more than 15 minutes. It releases the secondary reserve and brings the frequency back to its nominal value. The tertiary reserves are manually activated after a longer period of imbalance and does not need to be "spinning reserves" [2].

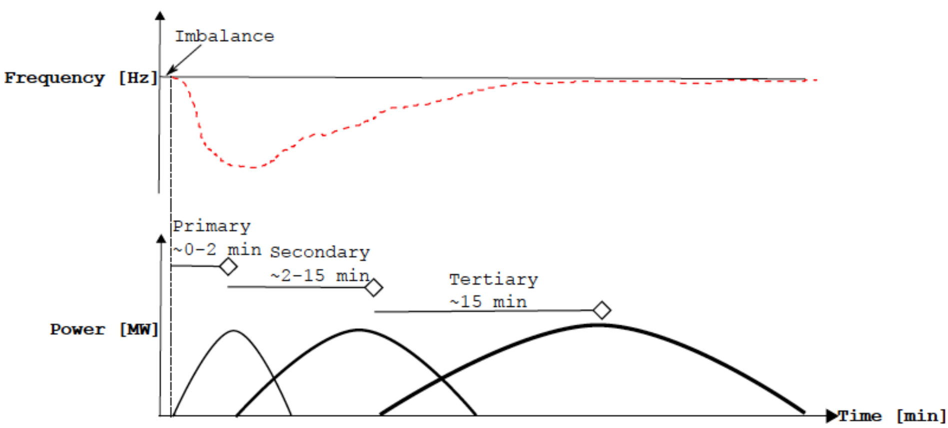

Figure B.3: Frequency imbalance and activation of balancing reserves [2]

Market participants

The participants in the balancing markets are the TSO, the Balancing Service Provider (BSP) and the Balancing Responsible Party (BRP). The TSO is responsible for the balancing market and has to make sure enough reserves are available at all time. The BSP are the party selling reserve procurements while the BRP are the party not able to fulfill cleared volume in the Day-ahead market.

Primary, secondary and tertiary reserve markets

There are separate markets for primary, secondary and tertiary reserves. The primary reserve market is national and divided into a weekly and a daily market. The reserves are provided by droop setting for the generators, providing a margin for the spinning reserves. The two products traded are power reserves and named Frequency Control for Normal operation, FCR-N, and Frequency Controlled Regulation for Contingencies, FCR-D. FCR-N is activated automatically in both directions (up/down) within 49.90-50.10 Hz while FCR-D is activated up if the frequency falls below 49.50 Hz. [2]

The secondary reserve market is a weekly, national market. The products are reserve capacity and activated reserve energy. The reservation of up and down regulation is handled separately. The reserves are activated automatically by adjusting the individual generators set points. The activation is done by signals from the TSO, Statnett. [2]

The market for the tertiary reserves is distinguished between two markets; FRR-M (RK in Norwegian) and RKOM. FRR-M, the tertiary reserve energy market, is a common Nordic market for balancing power. RKOM, the Norwegian regulating power option market, is the tertiary reserve capacity market in Norway used to secure enough tertiary reserves in the Norwegian part of the FRR-M. RKOM is divided into a weekly and seasonal market. In the season market the capacity is bough for lasting throughout the whole winter, usually for week 45-16. [2]

C Optimization, example

This appendix are taken from the authors specialization project, *Literature study: Modelling the Norwegian power system to quantify the value of reserves in 2050* [1], as specified in Section 1.3.

$$C_{total} = \sum_i \sum_t MC_i * Q_{i,t} \tag{C.1}$$

st.

$$\sum_{t,i} Q_{i,t} = D_t \tag{C.2}$$

$$Q_{i,t} \leq Qi^{MAX} \tag{C.3}$$

$$Q_{i,t} \geq Qi^{MIN} \tag{C.4}$$

$$\sum_{t,i} (Q_i^{MAX} - Q_{i,t}) \geq R_t \tag{C.5}$$

Case 1: No reserve requirement

In Case 1, the reserve requirement is set to zero.

Table C.1: Example optimization: Variables, Case 1

Name of variable	Variable index	Value	Unit
Time periods (load periods)	T	3	
Number of generators	N_t	3	
Marginal cost, generator i	MC_i	200, 300, 500	NOK/MWh
Minimum production, generator i	Q_i^{MIN}	500, 200, 100	MW
Maximum production, generator i	Q_i^{MAX}	1 000, 500, 300	MW
Demand, time period t	D_t	900, 1 550, 1 400	MW
Reserve requirement, time period t	$R_t = R$	0	MW

- Each of the time periods are one hour.
- The cost production cost for each time period is found by multiplying the

marginal cost of the generator with the required amount of power for one hour.

- The optimal solution is found by summing the minimum production cost over the time periods.

Table C.2: Example optimization: Solution, Case 1

Time period (demand) **State of generators**	**t = 1 (900 MW + 0 MW)**	**t = 2 (1 550 MW + 0 MW)**	**t = 3 (1 400 MW + 0 MW)**
1 / 0 / 0	900 MW * 1 h * 200 NOK/ MWh = 180 000 NOK	n.a.	n.a.
1 / 1 / 0	(700 MW * 1 h * 200) + (200 MW * 1 h * 300 NOK/ MWh) = 200 000 NOK	n.a.	(1 000 MW * 1 h * 200 NOK/ MWh) + (400 MW * 1 h * 300 NOK/MWh) = 320 000 NOK
1 / 1 / 1	(600 MW * 1 h * 200 NOK/ MWh) + (200 * 1 h * 300 NOK/MWh) + (100 MW * 1 h * 500 NOK/MWh) = 230 000 NOK	(1 000 MW * 1 h * 200 NOK/MWh) + (450 M * 1 h * 300 NOK/MWh) + 100 MW * 1 h * 500 NOK/ MWh) = 385 000 NOK	(1 000 MW * 1 h * 200 NOK/MWh) + (300 MW * 1 h * 300 NOK/MWh) + (100 MW * 1 h * 500 NOK/ MWh) = 340 000 NOK

The optimal solution of Case 1 is showed in green, which represent the lowest cost for fur filling the restrictions in the problem. The total operation costs are 180 000 NOK + 385 000 NOK + 320 000 NOK = 885 000 NOK.

Case 2: Reserve requirement

In Case 2, the reserve requirement is set to a non-zero value, R = 200 MW for each time period. All of the other variables and solution method are the same as in Case 1.

Table C.3: Example optimization: Variables, Case 2

Name of variable	**Variable index**	**Value**	**Unit**
Time periods (load periods)	T	3	
Number of generators	N_t	3	
Marginal cost, generator i	MC_i	200, 300, 500	NOK/MWh
Minimum production, generator i	Q_i^{MIN}	500, 200, 100	MW
Maximum production, generator i	Q_i^{MAX}	1 000, 500, 300	MW
Demand, time period t	D_t	900, 1 550, 1 400	MW
Reserve requirement, time period t	$R_t = R$	200	MW

Table C.4: Example optimization: Solution, Case 2

Time period (demand) **State of generators**	**t = 1 (900 MW + 200 MW)**	**t = 2 (1 550 MW + 200 MW)**	**t = 3 (1 400 MW + 200 MW)**
1 / 0 / 0	n.a.	n.a.	n.a.
1 / 1 / 0	(700 MW * 1 h * 200) + (200 MW * 1 h * 300 NOK/ MWh) = 200 000 NOK	n.a.	n.a.
1 / 1 / 1	(600 MW * 1 h * 200 NOK/ MWh) + (200 * 1 h * 300 NOK/MWh) + (100 MW * 1 h * 500 NOK/MWh) = 230 000 NOK	(1 000 MW * 1 h * 200 NOK/MWh) + (450 M * 1 h * 300 NOK/MWh) + 100 MW * 1 h * 500 NOK/MWh) = 385 000 NOK	(1 000 MW * 1 h * 200 NOK/ MWh) + (300 MW * 1 h * 300 NOK/MWh) + (100 MW * 1 h * 500 NOK/MWh) = 340 000 NOK

The optimal solution of Case 2 is showed in green. The total operation costs are 200 000 NOK + 385 000 NOK + 340 000 NOK = 925 000 NOK.

Cost of reserves

In Case 2, same amount of power are produced as in Case 1, but because of the reserve requirement the cost of production is higher. This is because Case 2 requires a margin of production capacity by the generators.

In Case 1 it is possible to only run generator 1 in the first time period, t = 1. This is not possible in Case 2, and both generator 1 and 2 must be on to be able to produce the required power and fur fill the required reserves. In this time period the cost of reserves equals the cost of running generator 2 instead of generator 1.

In the second time period, t = 2, the cost of reserves are zero because the cost of production are the same for the two cases.

In the third time period, t = 3, it is not possible to only run generator 1 and 2 in Case 2, and the cost of reserves equals the cost of having to run generator 3 instead of generator 2.

D Implemented data, original 4del

D.1 Detailed hydro systems

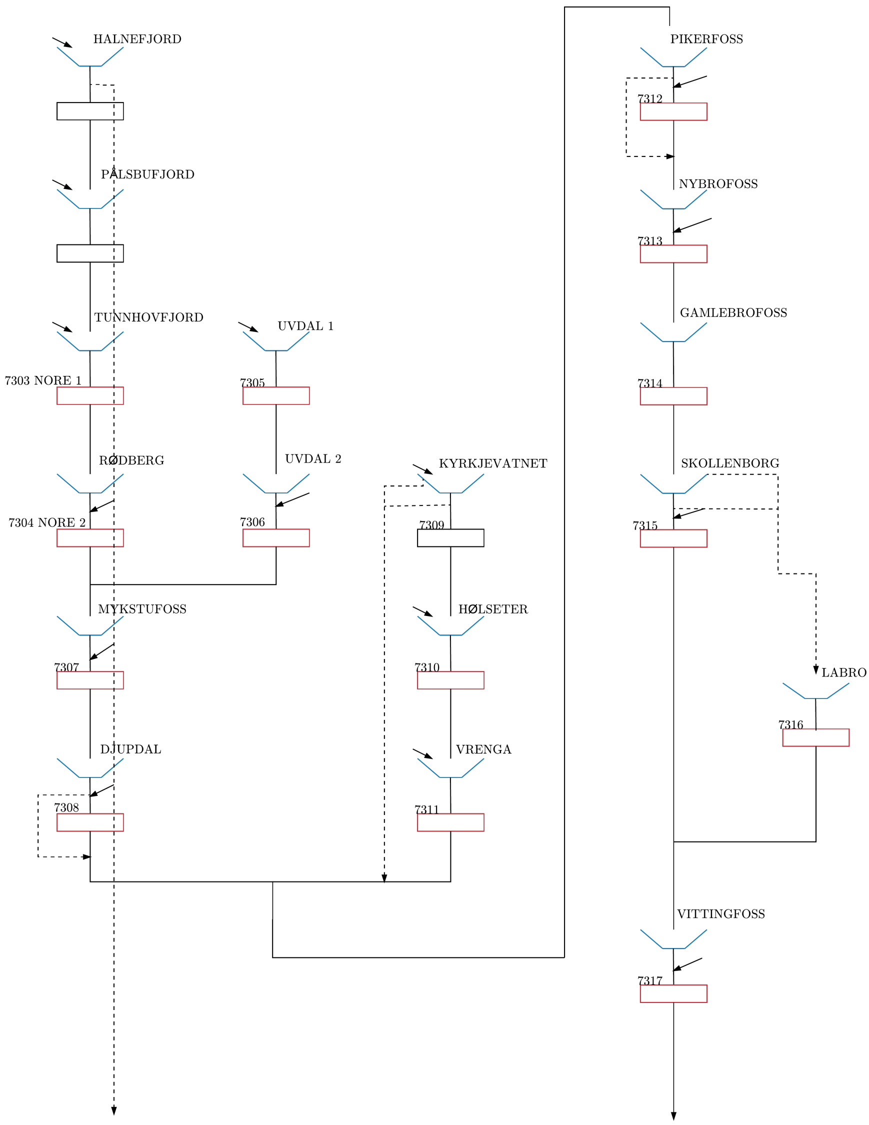

Figure D.1: Detailed hydro system, NUM

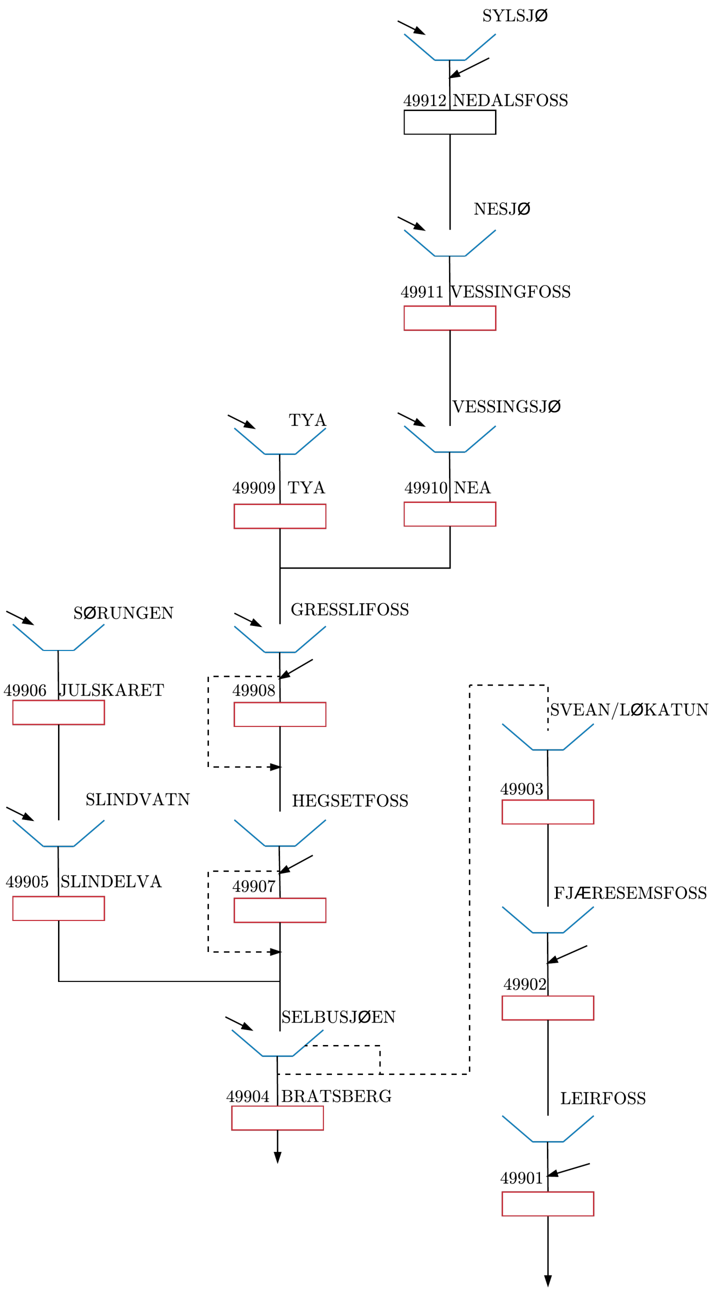

Figure D.2: Detailed hydro system, TEV

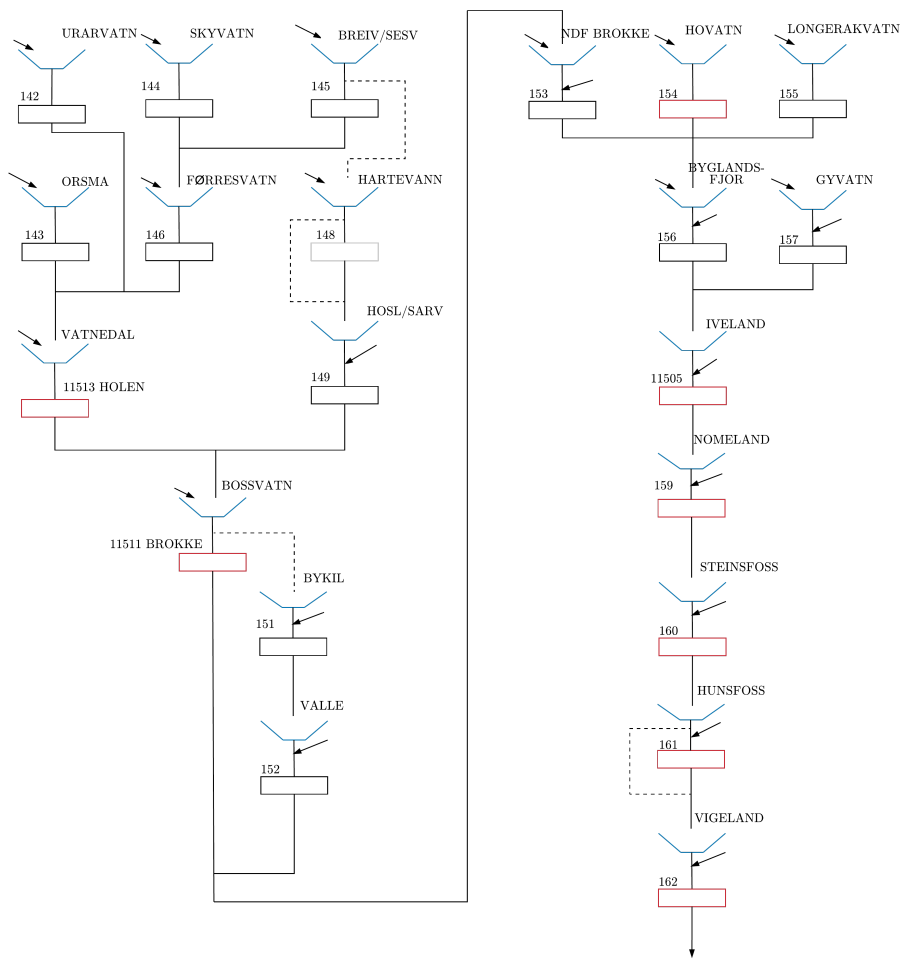

Figure D.3: Detailed hydro system, OTRA

D.2 Demand and market

D.2.1 Node 1: NUM

Firm power, fixed demand

Table D.1: Fixed demand in simulation period, NUM

Week number	1-52	53-104	105-156	SUM 1-156
Fastkraft, allmenn forsyning [GWh/year]	2 000	2 000	2 000	6 000
Fastkraft, industri 95 [GWh/year]	925	925	925	2775
SUM	2 925	2 925	2 925	8 775

Price dependent demand, elastic demand

No price dependent market were initially present in the data set.

Generation

All generation have 100 percent availability.

Table D.2: Generation in simulation period, NUM

Category, name	Installed capacity [MW]	Week number	Price [øre/kWh]
VARME, Varmekraft1	0,58	1-156	0
VARME, Varmekraft2	0,64	1-156	1
VARME, Varmekraft3	0,89	1-156	9,6
VARME, Varmekraft4	0,53	1-156	14,3
VARME, Varmekraft5	1,32	1-156	17
VARME, Varmekraft6	0,26	1-156	19,8
VARME, Varmekraft7	0,9	1-156	45
Rationing			362

Exchange

No exchange were initially present in the data set.

D.2.2 Node 2: TEV

Firm power, fixed demand

Table D.3: Fixed demand in simulation period, TEV

Week number	1-52	53-104	105-156	SUM 1-156
Fastkraftprognose [GWh/year]	2 000	2 000	2 000	6 000
Fastkraft, industri 95 [GWh/year]	82,51	82,51	82,51	247,53
SUM	2 082,51	2 082,51	2 082,51	6 247,53

Price dependent demand, elastic demand

No price dependent market were initially present in the data set.

Generation

All generation have 100 percent availability.

Table D.4: Generation in simulation period, TEV

Category, name	Installed capacity [MW]	Week number	Price [øre/kWh]
Flomkraft			0,01
Rationing			445

Exchange

Table D.5: Exchange volume in simulation period, TEV

Category, name	Exchange volume [GWh]	Week number	Price [øre/kWh]
Salgtrinn, Kjelkraft25	30,00	1-156	24,6

D.2.3 Node 3: OTRA

Firm power, fixed demand

Table D.6: Fixed demand in simulation period, OTRA

Week number	1-52	53-104	105-156	SUM 1-156
Fastkraft, fastkraft [GWh/year]	2 500	2 500	2 500	7 500
Fastkraft, industri 95 [GWh/year]	500	0	0	500
SUM	3 000	2 500	2 500	8 000

Price dependent demand, elastic demand

No price dependent market were initially present in the data set.

Generation

All generation have 100 percent availability.

Table D.7: Generation in simulation period, OTRA

Category, name	Price [øre/kWh]
Rationing	350

Exchange

Table D.8: Exchange volume in simulation period, OTRA

Category, name	Exchange volume [GWh]	Week number	Price [øre/kWh]
Kjøpstrinn, Varmekraft1	0,44	1-156	1,0
Kjøpstrinn, Varmekraft2	0,10	1-156	4,0
Kjøpstrinn, Varmekraft3	0,26	1-156	10,0
Kjøpstrinn, Varmekraft4	0,17	1-156	15,0
Kjøpstrinn, Varmekraft5	0,83	1-156	17,0
Kjøpstrinn, Varmekraft6	0,78	1-156	40,0

D.2.4 Node 4: TERM

Firm power, fixed demand

Table D.9: Fixed demand in simulation period, TERM

Week number	1-52	53-104	105-156	SUM 1-156
Fastkraftprognose [GWh/year]	1 000	1 000	1 000	3 000
SUM	1 000	1 000	1 000	3 000

Price dependent demand, elastic demand

No price dependent market were initially present in the data set.

Generation

All generation have 100 percent availability.

Table D.10: Generation in simulation period, TERM

Category, name	Installed capacity [MW]	Week number	Price [øre/kWh]
VARME, startkostnad	50,00	1-156	5,0
VARME, Gass1	50,00	1-156	20,0
VARME, Gass2	30,00	1-156	24,0
Flomkraft			0,01
Rationing			445

Start-up costs

Only one unit is charged with start-up costs; the unit "VARME, startkostnad" has an installed capacity of 50 MW, has a minimum capacity of 10 % of the installed capacity and has a start-up cost of 100 000 NOK.

Exchange

Table D.11: Exchange volume in simulation period, TERM

Category, name	Exchange volume [GWh]	Week number	Price [øre/kWh]
Salgtrinn, Kjelkraft25	30,00	1-104	24,0
	30,00	105-156	26,0

D.3 Transmission capacity

Table D.12: Transmission capacity between the nodes [MW]

from \to	NUM	TEV	OTRA	TERM
Numedal	-	200	200	-
Trondheim	200	-	200	-
Otra	200	200	-	150
TERM	-	-	150	-

Table D.13: Losses in the transmission lines [percentages]

fra \til	Numedal	Trondheim	Otra	TERM
Numedal	-	0	0	-
Trondheim	0	-	0	-
Otra	0	0	-	0
TERM	-	-	3	-

Table D.14: Transmission fee [øre/kWh]

fra \til	Numedal	Trondheim	Otra	TERM
Numedal	-	0.001	0.001	-
Trondheim	0.001	-	0.001	-
Otra	0.001	0.001	-	0.001
TERM	-	-	0.001	-

The transmission fee is only symbolic and does not have any impact on the results when sat to these values.

E Data convention, e-Highway2050

This appendix show the method for converting the data from relative to the scenarios e-Highway2050 project to relative to the scenarios and nodes in 4del and present the data. The scaling factor are decided by the given hydro capacity in the nodes in 4del, since the hydro capacities are fixed for 4del.

The method is only relevant for the hydro dominated nodes.

Nomenclature

i	Node in 4del, i = NUM, TEV, OTRA
j	Cluster in e-Highway, j = 79NO, 80NO, 81NO, 82NO, 83NO
$P_{hydro,i}$	Hydro capacity in node i
$P^{org}_{hydro,j}$	Original hydro capacity in cluster j
$P^{sc}_{hydro,j}$	Scaled hydro capacity in cluster j
$part_{i,j}$	Share of hydro from cluster j in node i
sc_j	Scaling factor, cluster j
$P^{org}_{wind,j}$	Original wind capacity in cluster j
$P^{sc}_{wind,j}$	Scaled wind capacity in cluster j
$P^{org}_{solar,j}$	Original solar capacity in cluster j
$P^{sc}_{solar,j}$	Scaled solar capacity in cluster j
$P^{org}_{thermal,j}$	Original thermal capacity in cluster j
$P^{sc}_{thermal,j}$	Scaled thermal capacity in cluster j
D^{org}_j	Original demand in cluster j
D^{norm}_j	Scaled demand in cluster j

Mathematical model for the generation in the hydro dominated nodes

For each node in 4del model, the hydro capacity is given: $P_{hydro,i}$. For each cluster in the e-Highway data set, the hydro, thermal, wind and solar capacities are given: $P^{org}_{hydro,j}$, $P^{org}_{thermal,j}$, $P^{org}_{wind,j}$ and $P^{org}_{solar,j}$.

The new capacities in the nodes (4del) will be given by data from one or two of the clusters clusters (e-Highway). The sum of the scaled values of the new hydro capacity in the clusters within the relative node have to be equal to the hydro capacity in the relative node:

$$P_{hydro,i} = \sum_{i,j} P^{sc}_{hydro,j} \tag{E.1}$$

To find the value of $P^{sc}_{hydro,j}$, the share of the hydro capacity of each of the clusters in the relative node is found, and the scaled hydro capacity in the clusters are decided:

$$part_{i,j} = \frac{P^{org}_{hydro,j}}{\sum_{i,j} P^{org}_{hydro,j}} \tag{E.2}$$

$$P^{sc}_{hydro,j} = part_{i,j} * P_{hydro,i} \tag{E.3}$$

The scaled cluster hydro capacities can be checked by inserting the numbers in Equation E.1.

The scaled cluster hydro capacities are used to find the scaling factor for the cluster, by dividing the scaled hydro capacity by the original hydro capacity:

$$sc_j = \frac{P^{sc}_{hydro,j}}{P^{org}_{hydro,j}} \tag{E.4}$$

The scaled thermal, wind and solar capacities for the clusters are found from the scaling factor and the original, e-Highway, capacities:

$$P^{sc}_{wind,j} = sc_j * P^{org}_{wind,j} \tag{E.5}$$

$$P^{sc}_{solar,j} = sc_j * P^{org}_{solar,j} \tag{E.6}$$

$$P^{sc}_{thermal,j} = sc_j * P^{org}_{thermal,j} \tag{E.7}$$

Mathematical model for the demand in the hydro dominated nodes

Demand values obtained from data source are normalized by the scaling factor, sc_j.

$$D^{norm}_j = sc_j * D^{org}_j \tag{E.8}$$

F Calibration

This appendix is the addition to Section 5.3. It provides Figures to support the explanation of the calibration process described in Section 5.3.

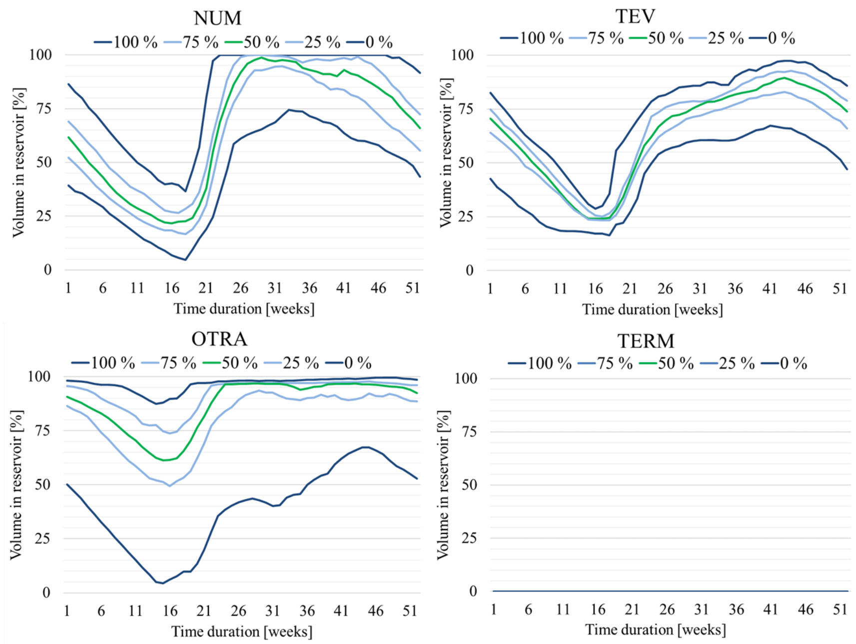

Figure F.1: Final handling of reservoirs, scenario X5 with 70% of e-Highway2050 demand in TERM

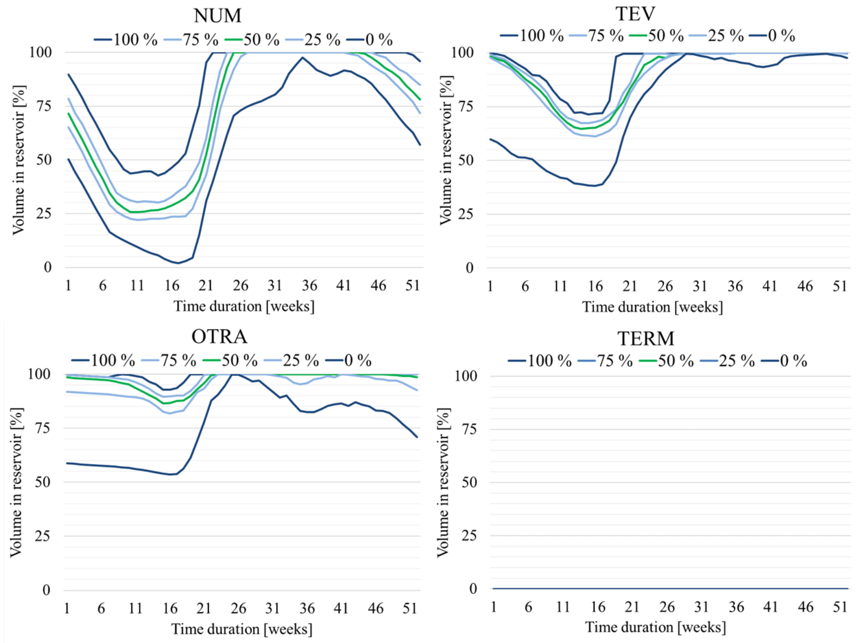

Figure F.2: Initial handling of reservoirs, scenario X7 with scaled e-Highway2050 values

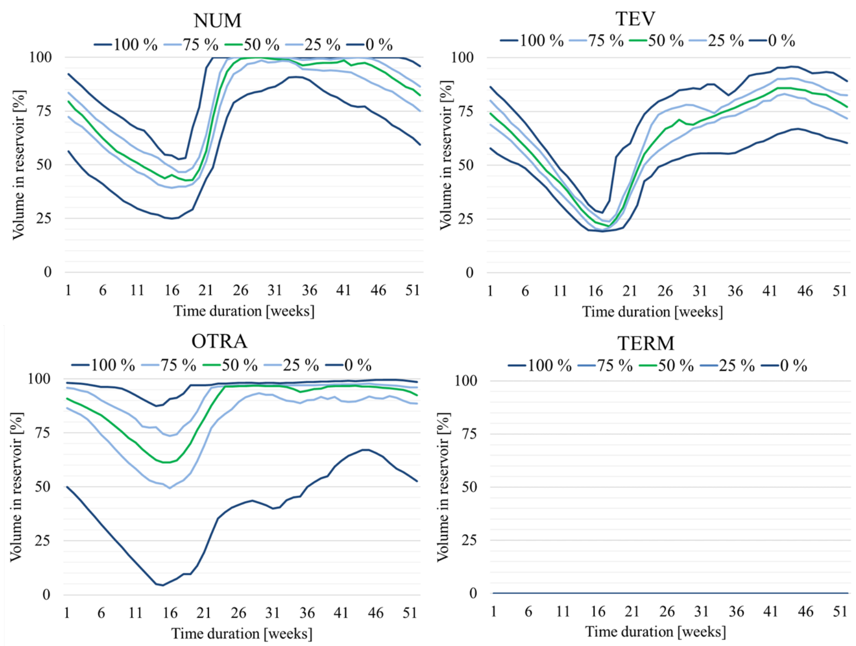

Figure F.3: Final handling of reservoirs, X7 with 85% of e-Highway2050 demand in TERM

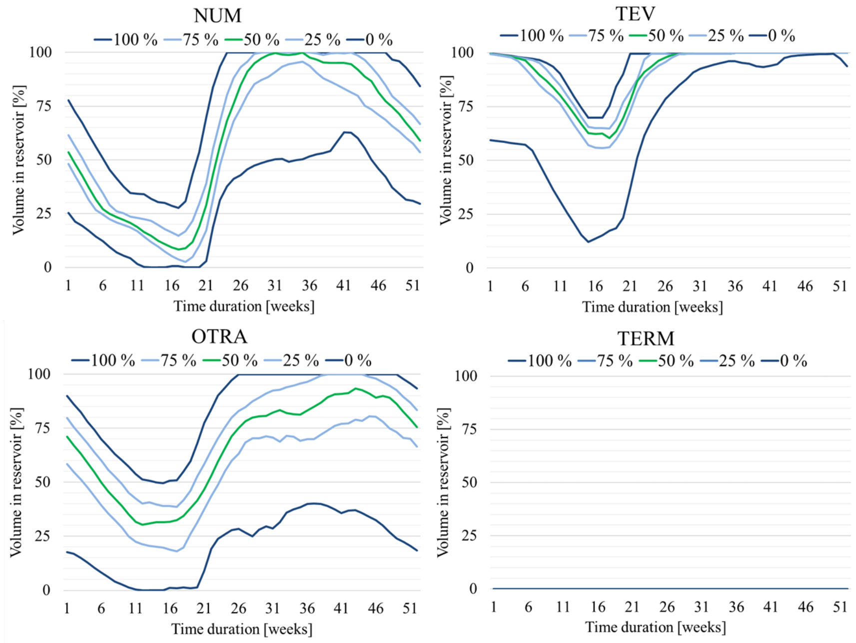

Figure F.4: Initial handling of reservoirs, scenario X16 with scaled e-Highway2050 values

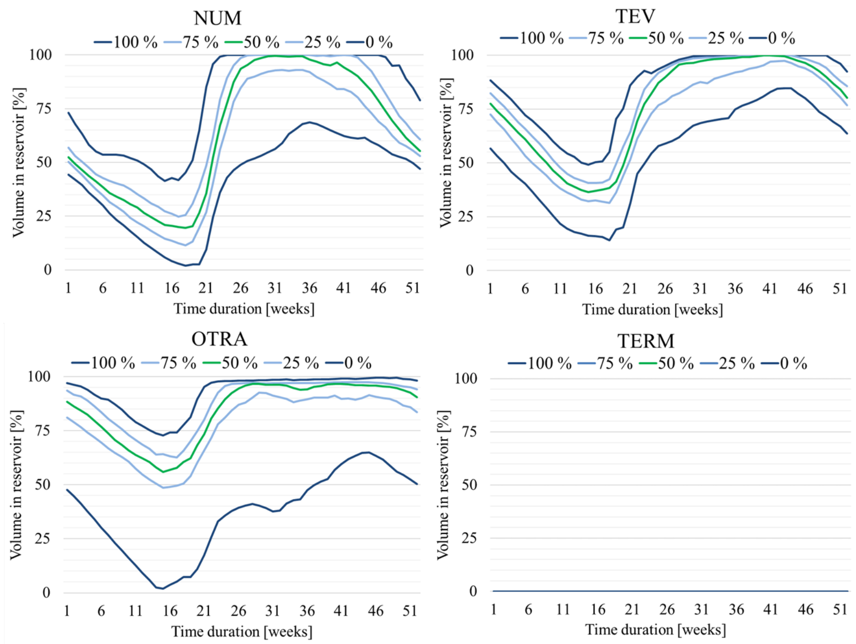

Figure F.5: Final handling of reservoirs, X16 with 90% of e-Highway2050 demand in TERM

G Implemented data, scenarios

G.1 Scenario X5: Large scale RES

Table G.1: Detailed thermal generation capacity [MW] and price [€/MWh], scenario X5

Node	Name	Capacity [MW]	Week number	Price [€/MWh]
NUM	Bio	13,46	1-156	22
	Gas	26,91	1-156	56,67
	Rationing		1-156	362
TEV	Flooding		1-156	0,01
	Rationing		1-156	445
OTRA	Rationing		1-156	350
TERM	Bio	3 250	1-156	22
	Gas1	250	1-156	52,70
	Gas2	250	1-156	53,70
	Gas3	250	1-156	54,70
	Gas4	250	1-156	55,70
	Gas5	250	1-156	56,70
	Gas6	250	1-156	57,70
	Gas7	250	1-156	58,70
	Gas8	250	1-156	59,70
	Gas9	500	1-156	52,20
	Gas10	500	1-156	51,70
	Gas11	500	1-156	51,20
	Gas12	500	1-156	50,70
	Coal1	200	1-156	73,10
	Coal2	200	1-156	73,60
	Coal3	600	1-156	72,60
	Coal4	600	1-156	72,10
	Flooding		1-156	0,01
	Rationing		1-156	445

Table G.2: Demand volume [GWh] for simulation period, scenario X5

Node	Category, name	Demand volume [GWh]	Week number
NUM	FIRM, Demand	3 401,3	1-52
	FIRM, Demand	3 401,3	53-104
	FIRM, Demand	3 401,3	105-156
TEV	FIRM, Demand	2 460,9	1-52
	FIRM, Demand	2 460,9	53-104
	FIRM, Demand	2 460,9	105-156
OTRA	FIRM, Demand	1 392,8	1-52
	FIRM, Demand	1 392,8	53-104
	FIRM, Demand	1 392,8	105-156
TERM	FIRM, Demand	115 420,9	1-52
	FIRM, Demand	115 420,9	53-104
	FIRM, Demand	115 420,9	105-156

Table G.3: Start-up costs [€], scenario X5

Node	Name	Capacity [MW]	Start-up cost [€]
NUM	Bio	13,46	0
	Gas	26,91	645,9
TERM	Bio	3 250	0
	Gas1	250	6 000
	Gas2	250	6 000
	Gas3	250	6 000
	Gas4	250	6 000
	Gas5	250	6 000
	Gas6	250	6 000
	Gas7	250	6 000
	Gas8	250	6 000
	Gas9	500	12 000
	Gas10	500	12 000
	Gas11	500	12 000
	Gas12	500	12 000
	Coal1	200	21 000
	Coal2	200	21 000
	Coal3	600	29 400
	Coal4	600	29 400

G.2 Scenario X7: 100 percent RES

Table G.4: Detailed thermal generation capacity [MW] and price [€/MWh], scenario X7

Node	Name	Capacity [MW]	Week number	Price [€/MWh]
NUM	Bio	12,60	1-156	22
	Rationing		1-156	362
TEV	Flooding		1-156	0,01
	Rationing		1-156	445
OTRA	Bio	9,8	1-156	22
	Rationing		1-156	350
TERM	Bio	6 250	1-156	22
	Gas1	250	1-156	52,70
	Gas2	250	1-156	53,70
	Gas3	250	1-156	54,70
	Gas4	250	1-156	55,70
	Gas5	250	1-156	56,70
	Gas9	500	1-156	52,20
	Gas10	500	1-156	51,70
	Gas11	500	1-156	51,20
	Flooding		1-156	0,01
	Rationing		1-156	445

Table G.5: Demand volume [GWh] for simulation period, scenario X7

Node	Category, name	Demand volume [GWh]	Week number
NUM	FIRM, Demand	2 600,6	1-52
	FIRM, Demand	2 600,6	53-104
	FIRM, Demand	2 600,6	105-156
TEV	FIRM, Demand	1 881,3	1-52
	FIRM, Demand	1 881,3	53-104
	FIRM, Demand	1 881,3	105-156
OTRA	FIRM, Demand	1 064,9	1-52
	FIRM, Demand	1 064,9	53-104
	FIRM, Demand	1 064,9	105-156
TERM	FIRM, Demand	114 458,5	1-52
	FIRM, Demand	114 458,5	53-104
	FIRM, Demand	114 458,5	105-156

Table G.6: Start-up costs [€], scenario X7

Node	Name	Capacity [MW]	Start-up cost [€]
NUM	Bio	13,46	0
TERM	Bio	6 250	0
	Gas1	250	6 000
	Gas2	250	6 000
	Gas3	250	6 000
	Gas4	250	6 000
	Gas5	250	6 000
	Gas9	500	12 000
	Gas10	500	12 000
	Gas11	500	12 000

G.3 Scenario X16: Small and local

Table G.7: Detailed thermal generation capacity [MW] and price [€/MWh], scenario X16

Node	Name	Capacity [MW]	Week number	Price [€/MWh]
NUM	Rationing		1-156	362
TEV	Flooding		1-156	0,01
	Rationing		1-156	445
OTRA	Bio	30,00	1-156	22
	Rationing		1-156	350
TERM	Bio	3 750	1-156	22
	Gas1	250	1-156	52,70
	Gas2	250	1-156	53,70
	Gas3	250	1-156	54,70
	Gas4	250	1-156	55,70
	Gas5	250	1-156	56,70
	Gas6	250	1-156	57,70
	Gas9	500	1-156	52,20
	Gas10	500	1-156	51,70
	Gas11	500	1-156	51,20
	Coal1	200	1-156	73,10
	Coal3	600	1-156	72,60
	Flooding		1-156	0,01
	Rationing		1-156	445

Table G.8: Demand volume [GWh] for simulation period, scenario X16

Node	Category, name	Demand volume [GWh]	Week number
NUM	FIRM, Demand	3 579,0	1-52
	FIRM, Demand	3 579,0	53-104
	FIRM, Demand	3 579,0	105-156
TEV	FIRM, Demand	2 589,2	1-52
	FIRM, Demand	2 589,2	53-104
	FIRM, Demand	2 589,2	105-156
OTRA	FIRM, Demand	1 465,6	1-52
	FIRM, Demand	1 465,6	53-104
	FIRM, Demand	1 465,6	105-156
TERM	FIRM, Demand	84 263,4	1-52
	FIRM, Demand	84 263,4	53-104
	FIRM, Demand	84 263,4	105-156

Table G.9: Start-up costs [€], scenario X16

Node	Name	Capacity [MW]	Start-up cost [€]
TERM	Bio	3 250	0
	Gas1	250	6 000
	Gas2	250	6 000
	Gas3	250	6 000
	Gas4	250	6 000
	Gas5	250	6 000
	Gas6	250	6 000
	Gas9	500	12 000
	Gas10	500	12 000
	Gas11	500	12 000
	Coal1	200	21 000
	Coal3	600	29 400

H Additions to data set 4del

H.1 Transmission capacity

```
 'MASKENETT',4,   30,    50,    40,    48,
 1,'numedal',2,'tev',
 0.0,0.001,0.001,
 0,200.00,200.00,
 0,
 2,'tev',3,'otra',
 0.0,0.001,0.001,
 0,200.00,200.0,
 0,
 3,'otra',1,'numedal',
 0.0,0.001,0.001,
 0,200.0,200.0,
 0,
 3,'otra',4,'term',
 3.0,0.001,0.001,
 0,150.0,150.0,
 0,
-1,'AVSLUTT',-1,'SLUTT'


For hver overf|ringslinje:
Omr}denr.fra, Omr}denavn fra, Omr}denr.til, Omr}denavn til
Tap (%), Avgift fra-til, Avgift til-fra, Kapasitet fra-til (MW), Kap. til-fra
Antall revisjoner,
```

Figure H.1: File describing the characteristics of the transmission lines, valid for all data sets

H.2 Price segments

```
1,   * Versjonsnummer p} fil
4,   * Antall prisavsnitt
1,'P1                  ',* Avsnitt nr, Navn
2,'P2                  '
3,'P3                  '
4,'P4                  '
3,   3,   3,   3,   3,   3,   3,   3,   1,   1,   1,   1,   1,   1,   2,   2,   2,   2,   2,   2,   2,   2,   2,   2,Mon
3,   3,   3,   3,   3,   3,   3,   3,   1,   1,   1,   1,   1,   1,   2,   2,   2,   2,   2,   2,   2,   2,   2,   2,Tue
3,   3,   3,   3,   3,   3,   3,   3,   1,   1,   1,   1,   1,   1,   2,   2,   2,   2,   2,   2,   2,   2,   2,   2,Wed
3,   3,   3,   3,   3,   3,   3,   3,   1,   1,   1,   1,   1,   1,   2,   2,   2,   2,   2,   2,   2,   2,   2,   2,Thu
3,   3,   3,   3,   3,   3,   3,   3,   1,   1,   1,   1,   1,   1,   2,   2,   2,   2,   2,   2,   2,   2,   2,   2,Fri
4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,Sat
4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,   4,Sun
```

Figure H.2: Price segments, valid for all data sets

H.3 Wind and solar energy series and capacity

Figure H.3 show the set-up for including energy series for wind and solar and link them to installed capacity: The files with the name '"cluster"_W.V30' and '"cluster"_PV.V30' are wind and sun series files for the relative cluster. The energy series files are used to describe the wind and solar power production in GWh/time period. The series are based on measured data from the time period. To match (hydro) inflow files of 50 years, the five years in wind- and solar series are repeated ten times in the files. Each time series file are scaled with the relative scaling factor (Norwegian: Omregningsfaktorer) to match the capacity in the cluster. In this project, the hourly time series was used, and the time series are given in [MWh/h = MW]. The scaling factor for the given scenario is divided by 1000 to get the value on the wind and solar production capacity in [GWh/h].

```
    4,    * Antall delomr{der med vindenergifiler
    1,    4,    * Delom{denr, antall vindenergfiler
'80NO_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.1050,                        * Sluttuker, omregningsfaktorer
'82NO_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.1853,                        * Sluttuker, omregningsfaktorer
'80NO_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0031,                        * Sluttuker, omregningsfaktorer
'82NO_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0033,                        * Sluttuker, omregningsfaktorer
'#Slutt',   999.900,   * Sluttegn for vindkraftproduksjon
    2,    2,    * Delom{denr, antall vindenergfiler
'83NO_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.3263,                        * Sluttuker, omregningsfaktorer
'83NO_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0106,                        * Sluttuker, omregningsfaktorer
'#Slutt',   999.900,   * Sluttegn for vindkraftproduksjon
    3,    4,    * Delom{denr, antall vindenergfiler
'79NO_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0685,                        * Sluttuker, omregningsfaktorer
'81NO_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0507,                        * Sluttuker, omregningsfaktorer
'79NO_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0023,                        * Sluttuker, omregningsfaktorer
'81NO_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    0.0023,                        * Sluttuker, omregningsfaktorer
'#Slutt',   999.900,   * Sluttegn for vindkraftproduksjon
    4,    4,    * Delom{denr, antall vindenergfiler
'31DE_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,   32.1599,                        * Sluttuker, omregningsfaktorer
'38DK_W.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,   13.6679,                        * Sluttuker, omregningsfaktorer
'31DE_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    8.2259,                        * Sluttuker, omregningsfaktorer
'38DK_PV.V30',   100.000,   * Fil med vindkraftproduksjon, Eierandel
 156,    1.8019,                        * Sluttuker, omregningsfaktorer
'#Slutt',   999.900,   * Sluttegn for vindkraftproduksjon
```

Figure H.3: File linking energy series with capacity, valid for scenario X5

H.4 Parameters for automatic calibration

The parameters for the automatic calibration was developed in cooperation with Stefan Jahnert, SINTEF Energy, to provide the best fitted strategy for the data set. The file is rendered in Figure H.4.

Antall hovediterasjoner	, 5
Steglengde	,0.100,0.100,0.100
Prosentvis steglengde i neste	hoveditera ,0.800
Omradenummer , Omradenavn , Tilbakekobling , Form , Elastisitet	
1, NUMEDAL , 3, 6, 0	
2, tev , 2, 5, 0	
3, otra , 1, 4, 0	
4, term , 0, 0, 0	
Omradenummer , Omradenavn , Vekting av samf.ok. overskudd	
1, NUMEDAL ,1.000	
2, tev ,1.000	
3, otra ,1.000	
4, term ,1.000	

Figure H.4: Parameters used to auto calibrate the scenarios