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Impact of a Large Implementation of ZEBs in the Norwegian Power System

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Submission date: April 2016
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Abstract

In the Energy Performance of Buildings Directive (EPBD), all new buildings are said to be nearly Zero Energy Buildings (ZEBs) from 2018/2020 [1]. A Zero Energy Building is a building that has a lower demand for energy, and is able to produce the same amount of energy which it uses during the year [2].

This thesis analyzes the impact of a large implementation of ZEBs in the Norwegian power system. With an expected increasing share of ZEB due to the EPBD, it is important to analyze the impact on the power system, in order to prepare the power system for the consequences of such large changes. The analysis is performed by running simulations in the EMPS model. Several cases has been analyzed, and they differ from each other by the share of ZEBs, choice of heating technology, demand and PV-production.

The model setup contains projections of demand and installed capacity of different production technologies, as well as expected interconnections to surrounding countries in 2030.

A large implementation of ZEBs gives reduced demand during winter and increased PV-production during summer. This results in a increased surplus in the power balance in Norway of 23.8-37.4 TWh, depending on choice of heating technology, compared with the reference case BAU ("Business as usual"). The surplus of power decreases some in the other Nordic countries.

The total CO_2 emissions from power production within the Nordic countries is reduced, due to lower production from thermal power plants, mostly coal-fired plants. The reduction of CO_2 emissions is between 3.53 and 5.68 mill. tons for the ZEB-cases. The CO_2 emissions per kWh produced in the Nordic power system reduces from 97.8 gCO_2/kWh in the reference case to 87.3-83.2 gCO_2/kWh in the ZEB-cases.

The cases with increased PV-production has a significantly different reservoir handling than the cases without PV-production. The average reservoir level is lower due to the predictable PV-production in the summer. The reduction in reservoir level is between 6-11 percentage points throughout the year. The difference is highest in the spring and summer.

The average prices is reduced, especially in the summer. Also the classic price reduction during the spring inflow is amplified. In a chosen summer week the classic daily price profile is turned up side down in the cases with PV-production, giving the highest price during late evening and night. In a wet year the system experiences a price collapse, while in a dry year there is slightly an increase in price compared to a normal year. In the ZEB-cases the price collapse is present in several years.

Due to higher production and lower prices, the export increases. The share of maximum export is 6 % for the reference case, while it increases to 25-37 % for the ZEB-cases. Compared with the reference case BAU, where it is import during winter and export during summer, two out of three ZEB-cases will on a weekly, average level, only export power, during the year.

Sammendrag

I følge EUs Direktiv for bygningers energiytelse skal alle nye bygninger være nær nullenergibygg (ZEB) fra 2018/2020 [1]. Et nullenergibygg er en bygning ned lavt energibehov, og som dekker det årlige energibehovet med lokal produsert energi [2]

Denne masteroppgaven analyserer effekten av en større utbredelse av ZEB i det norske kraftsystemet. Med en forventet økning i andelen av ZEB som følge av Direktivet for bygningers energiytelse, er det viktig å analysere effekten på kraftsystemet, for å kunne forberede kraftsystemet på konsekvensene av så store endringer. Analysen er gjort ved å kjøre simuleringer i Samkjøringsmodellen (EMPS). Det har blitt analysert flere cases som er forskjellige etter andelen ZEB, valg av oppvarmingsteknologi, forbruk og solkraftproduksjon.

Modeloppsettet innholder fremskrivninger av forbruk og installert kapasiet for ulike kilder for kraftproduksjon, samt forventede overføringslinjer- og kabler til nabolandene i 2030.

En større utbredelse av ZEB gir redusert lastbehov om vinteren og høyere solkraftproduksjon om sommeren. Dette fører til at kraftoverskuddet øker i Norge med 23,8-37,4 TWh, avhengig av valg av oppvarmingsteknologi, sammenlignet med referanse-caset BAU ("Business as usual"). Kraftoverskuddet reduseres noe i de andre nordiske landene.

De totale CO_2-utslippene fra kraftproduksjonen i de nordiske landene er redusert på grunn av lavere produksjon fra fossile termiske kraftverk, mesteparten fra kullkraftverk. Reduksjonen ligger mellom 3,53-5,68 millioner tonn CO_2 for ZEB-casene. CO_2-utslippene per kWh produsert i det nordiske kraftsystemet reduseres fra 97,8 gCO_2/kWh i referanse-caset til 87,3-83,2 gCO_2/kWh i ZEB-casene.

Casene med økt solkraftproduksjon har en signifikant forskjellig håndtering av vannmagasinene sammenlignet med de uten solkraftproduksjon inkludert referanse-caset. De gjennomsnittlige vannmagasinnivåene er lavere gjennom hele året som følge av den økte solkraftproduksjonen om sommeren. Reduksjonen i de gjennomsnittlige vannmagasinnivåene er mellom 6 og 11 prosentpoeng gjennom året. Forskjellen er høyest om våren og sommeren.

De gjennomsnittlige prisene redusres, spesielt om sommeren. Den klassiske prisre-

duksjonen om senvåren på grunn av vårflommen blir forstørret. I en valgt sommeruke blir den klassiske prisprofilen med høyest pris om morgenen og ettermiddagen, snudd opp ned i casene med solkraftproduksjon. I disse casene er prisen høyest om senkvelden og natten. I år med mye nedbør will systemene oppleve priskollaps, mens det i tørre år er en liten økning i pris sammenlignet med et normalt år. I ZEB-casene er priskollapsene tilstede i flere av årene.

PÅ grunn av høyere produksjon og lavere priser vil eksporten øke. Andelen av maksimal eksport er 6 % for referanse-caset, og vil øke til 25-37 % for ZEB-casene. I referanse-caset, hvor det på en gjennomsnittlig uke er import om vinteren og eksport om sommeren, vil to av tre ZEB-caser, med ukentlige og gjennomsnittlige verdier, kun ha eksport i løpet av året.

Problem description

According to the Energy Performance of Buildings Directive (EPBD), all new buildings are said to be nearly net Zero Energy Buildings (ZEBs) from 2018/2020 [1]. A net zero energy building is a building which has low energy demand, with so-called ”passive energy standard”, and has the capability to cover the energy demand by producing energy on-site [2]. The target of a ZEB is a yearly net balance; however, the building still exchanges electricity with the grid on an hourly or minute basis, as the production may not always correspond with the load at these time levels.

The overall task in this thesis is to investigate the effects of a large roll out of energy producing Zero Energy Buildings (ZEBs) in Norway towards 2030. ZEBs have both a) reduced heat demand and b) local electricity production, which both affect the use of the power grid. In the task the electricity load profile of the ZEBs and production from PV are separated, even though it is a net electricity load profile that the power grid ”sees”. The electricity load profiles of ZEBs will be provided by PhD student Karen Byskov Lindberg.

The analyis will be done with NVE's[1] 3-hour version of the EMPS-model for the year 2030, which includes the decided power cables to other countries and production capacity (new wind power and hydropower and some phased out nuclear power in Sweden). The model is expanded to include:

- Load profiles for electric cars in 2030 (projection by NVE)
- Production profiles for solar power in the 13 EMPS-areas in 2030.
- Load profiles for ZEBs and existing ”normal” buildings in the 13 EMPS-areas in 2030.

The following cases is to be analyzed:

1. A reference case assuming a ”normal” development of the building stock based on current policies.
2. A penetration of 50 % ZEBs in Norway in 2030, where the heating demand is covered by:

1. the Norwegian Water Resources and Energy Directorate

- Only electric heating, e.g. electric radiatiors
- Only heat pumps
- Only other heating, e.g. district heating or use of bio energy

3. A penetration of 50% passive buildings, but no on-site PV-production.
4. No change in demand compared with the reference case, but with on-site PV-production

The candidate shall analyze the effect on reservoirs, power export and prices, for wet years, dry years and average years.

Preface

This thesis completes my master's degree at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). The thesis was written in coordination with the Norwegian Water Resources and Energy Directorate (NVE).

I would like to express my appreciation to my co-supervisors Karen Byskov Lindberg and Eirik Øyslebø for sharing their knowledge, giving valuable advices, their patience and profitable discussions throughout the work. I would also like to thank my supervisor Gerard Doorman for interesting conversations and useful advices.

Furthermore I would like to thank the employees at NVE for interesting conversations during my stay there. I would especially like to thank Harald Endresen and Ellen Skaansar for their help and valuable discussions.

Finally, I wish to thank my fellow students and friends for their support, discussions and pleasant lunch breaks.

Tore Dyrendahl

Trondheim, April 2016

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1 | Introduction

1.1 ZEB

The international community has agreed to reduce their CO_2 emissions, in order to avoid serious consequences of climate changes. It is an agreement that the temperature rise should not exceed 2°C. Lowering the energy comsumption, aswell in the building sector, is a key factor for reducing the CO_2 emissions.

In the Energy Performance of Buildings Directive (EPBD), all new buildings are said to be nearly Zero Energy Buildings (ZEBs) from 2018/2020 [1]. A Zero Energy Building is a building that has a lower demand for energy compared with e.g. the energy performance as for today, and is able to produce the same amount of energy which it uses during the year [2].

In the Nordic region, the building sector uses on third of the final energy consumption in the region [3]. A large introduction of ZEBs will have major effect on the power system and how the buildings are integrated in the power system, due to reduced demand, on-site energy production and a different load profile. There are few studies of the effect of introducing a large implementation of ZEB in the Norwegian power system.

1.2 Objective

In this master thesis the impact of at large implenmentation of ZEB in the Norwegian power system is analyzed. The analysis will contain effects on power balance, reservoirs, import, export and prices, and is done for dry years, wet years and normal years. Few have seen the consequences of a large implementation of ZEB with local power production on the power system earlier. With an expected increasing share of ZEB due to the EPBD, it is important to analyze the impact on the power system, in order to prepare the power system for the consequences of such large changes.

1.3 Outline

This report begins with a background explaining ZEB, the Norwegian and Nordic power system and the EMPS model used to run the simulations. Chapter 3 presents and explain the model setup and model cases analyzed in this report. In Chapter 4 the results are shown and discussed, first with an overview of the power balance in the Nordic countries and effect on CO_2 emissions. Then results and discussion for reservoirs, prices and exchange is presented. Also results for the differences between a dry, normal and wet year are presented and discussed in the chapter. The results and discussion are followed by the conclusion and further work.

2 | Theory and background

2.1 ZEB

A Zero Energy Building (ZEB) is a building that has a lower demand for energy compared with e.g. the energy performance as for today, and is able to produce the same amount of energy that the building uses during the year [2]. The energy production does however, for most of the buildings, not cover the load demand at all times. It is therefore necessary with connection and exchange with an energy infrastructure at an hourly and minute level. Most ZEBs are connected to the energy infrastructure, and therefore the term net ZEB is more relevant. Connection with the energy infrastructure, gives an opportunity to interact with e.g. the power grid or district heating systems. This gives the advantage of utilizing the energy in other parts of the power system, optimize the capacity of energy sources and is benefical for the security of supply. From this point the term ZEB is used, also for situations where the ZEBs interact with the energy infrastructure. [2][4][5][6]

Each country affected by the Energy Performance of Buildings Directive is to determine a definition for ZEBs for their own country. In Norway, there is no official definition of ZEB yet. Even though there is no common definition for ZEB; there is a common understanding of the concept. Figure 2.1 shows a graphic representation of the concept of ZEB balance, where the first step is to reduce the demand through energy efficiency. The reduction of demand is from a reference building, e.g. the building performance as for today, to a passive building or a low energy building. Electricity generation and thermal energy carriers cover the remaining demand. The second step requires a supply equal to the demand in order to meet the zero balance line, as the figure shows.[4]

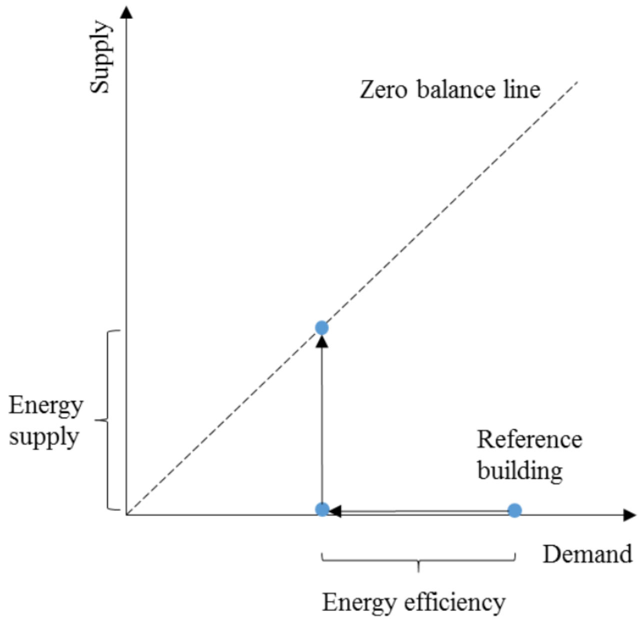

Figure 2.1: *A graphic representation of the concept of ZEB balance. Obtained from [4]*

2.2 The Norwegian and Nordic power system

Today the Nordic power system is highly dominated by hydropower and thermal power, as seen in Table 2.1. The Norwegian power system consists mostly of hydropower, while the Swedish power system has a large share of both nuclear power and hydropower. The share of unregulated hydropower is larger in Sweden than in Norway. In Finland, nuclear power and other thermal power dominate, with some hydropower. In Denmark, thermal power dominate the system, with an increasing share of wind power. Also Sweden has had an increase in wind power over the last years. Figure 2.2 shows the weekly production by type in the Nordic countries combined in the years 2011 to 2014. It also shows the variation throughout the year, which is mainly due to the variation of demand (high in winter).

Table 2.1: Power production by source in 2013 in Nordic countries. Numbers in TWh. [7][8][9][10]

Source	Norway	Sweden	Denmark	Finland	Nordic
Hydro	129.0	61.5	-	12.8	203.4
Nuclear	-	66.5	-	23.6	90.1
Thermal, fossil fuel	2.6	2.6	18.0	21.4	44.7
Thermal, biomass-waste	0.6	12.7	5.1	12.3	30.7
Wind	1.9	9.8	11.1	0.8	23.6
Other	0.2	-	0.5	0.3	1.0
Total	134.2	153.1	34.2	71.2	393.4

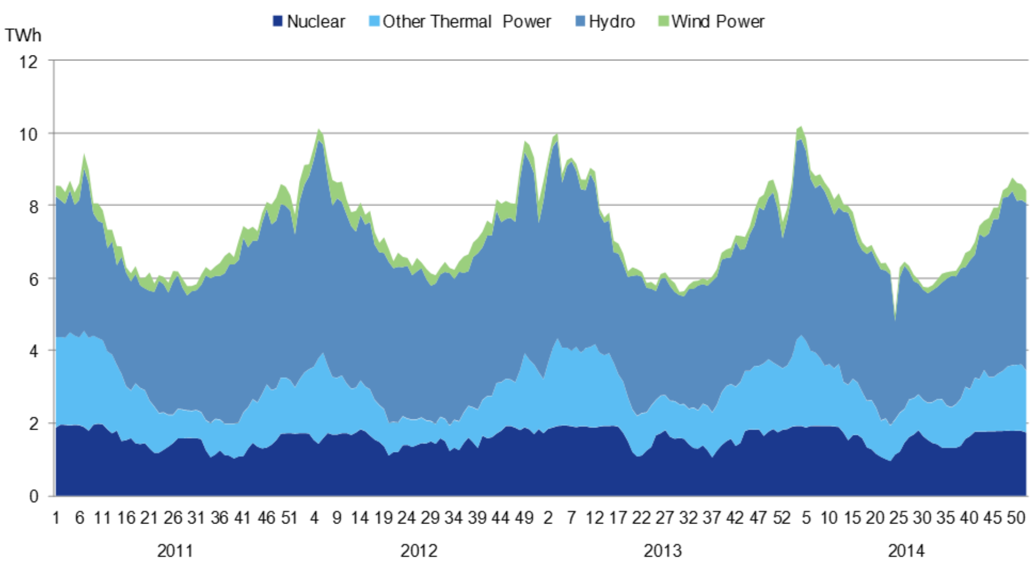

Figure 2.2: Nordic production by type from 2011 to 2014. [11]

Figure 2.3 illustrates the typical variation of hydropower and production in Norway. The inflow increases from week 14, which is mostly caused by the snow melting in the mountains. From week 30 the inflow stabilizes due to increased rainfall in the early autumn, and decreases at the end of the year when the precipitation falls as snow. We see that there are some unregulated hydropower, which to a large extend follow the inflow – the production peaks in late spring and early summer. The production from reservoirs peaks in the winter. During late spring and summer, the reservoir saves much of the inflow. [12][13]

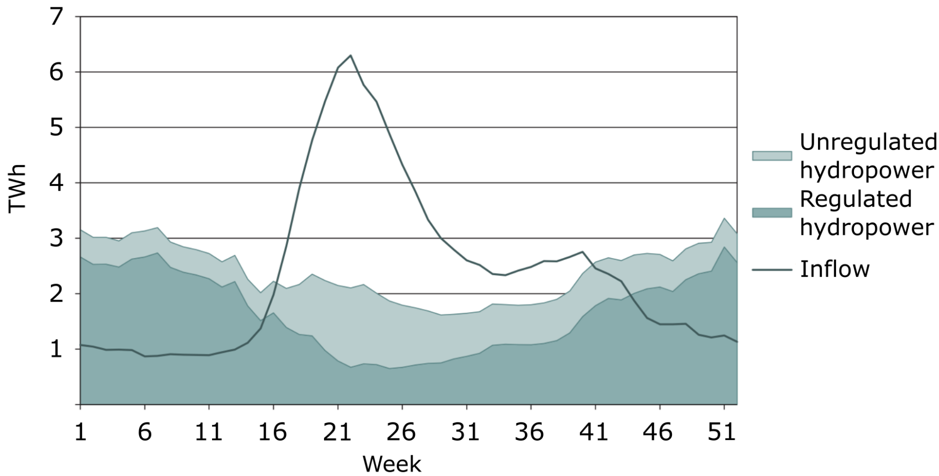

Figure 2.3: *Typical correlation between inflow and production over a year. [13]*

The inflow varies from year to year, due to varying precipitation and snow melting. Figure 2.4 shows the inflow variations in the Norwegian hydropower system from 1990 to 2011[1]. The variation is at 60 TWh in this period, with a normal inflow of 125.6 TWh. As the figure shows, there could be a large difference from year to year. In 1995 the inflow was just below 140 TWh, in 1996 approximately 93 TWh, before it increases again in 1997 to 125 TWh. The huge variations in inflow have a major impact on the power system in Norway and the other Nordic countries and the reservoir handling. [13]

Due to the large variations in inflow, the power system will depend more on the thermal power sources in dry years and vice versa. The ability to exchange power between areas is important to avoid high prices and shortage of power in deficit areas.

With an increasing share of intermittent renewables, the interaction between the different regions is important. The high share of regulated hydropower in the region

1. Assuming today's reservoir and power plant capacity

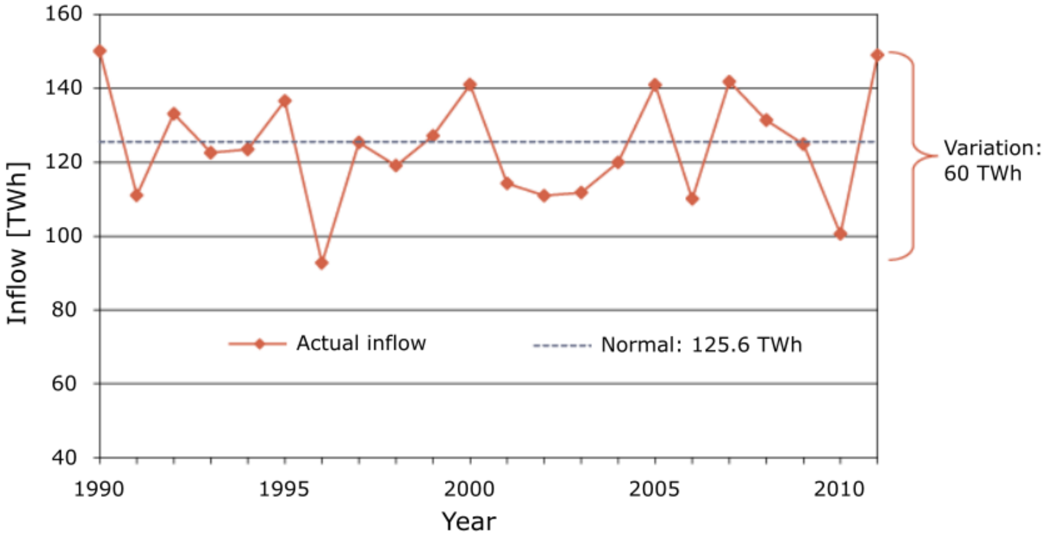

Figure 2.4: *Inflow variations in Norway from 1990 to 2011. [13]*

is useful, due to a increasing share of intermittent renewables, since hydropower can change the power production relatively quick. [13]

The Nordic countries are all part of the Nordic power market, where one common price is calculated for each hour for the entire Nordic market area. This price is based on the bids from producers and consumers. Because of restrictions in the power grid in some situations, there is also calculated prices in seperate price areas. An example of price areas[2], and the power flow between the them, in the Nordic and Baltic power systems is depicted in Figure 2.5. It shows the connections within the countries and exchange with neighbouring countries. [13]

2. as of January 29th

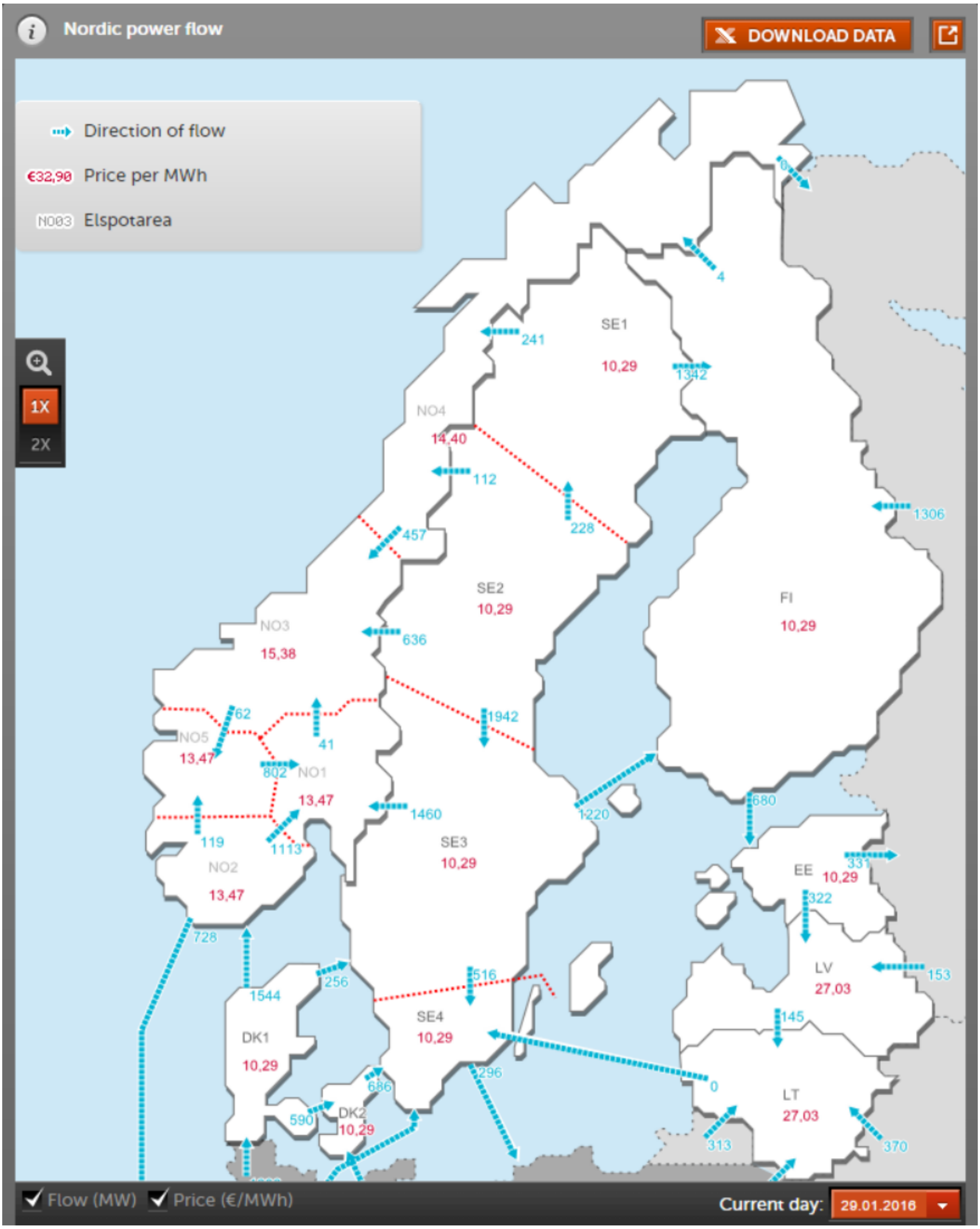

Figure 2.5: *Snapshot from Statnett's webpage of the power flow and price areas on January 29th, 2016 between 11 p.m. and 12 a.m. in the Nordic and Baltic countries. [14]*

2.3 The EMPS model

In a power system with a large share of hydropower and many uncertainties that must be taken into account, optimal scheduling of the power system a complex task. Examples of uncertainties are future inflow and demand, thermal generation and exchange with neighbouring countries. The EMPS model (EFI's Multi-Area Powermarket simulator) is a stochastic model for optimizing and simulation of power system operations dominated by hydropower. The model accounts the aforementioned kinds of uncertainties. The EMPS model is developed by SINTEF Energy Research. [12][15][16][17]

The EMPS model can be used to find results related to [15][12][16]:

- Hydro system operations
- Thermal generation
- Power prices
- Power consumptions
- Exchange between areas
- Economic results
- Emissions
- The incremental benefit figures of increasing the capacity of various facilities.

The EMPS model consists of two phases: A strategy phase and a simulation phase. In the strategy phase the water values are calculated, while in the simulation phase a system simulation is performed based on the water values found in the strategy phase for a sequence of hydrological years. [12][15]

This chapter gives a short description of the EMPS model, where the system model is explained first, followed by a more detailed explanation of the strategy and simulation phases. Further details about the EMPS model are found in [12].

2.3.1 The system model

The EMPS model is a multi-area model and uses data for a defined system, consisting of several geographic areas. The area division is based on several factors such as: Bottlenecks in the transmission systems, hydrological conditions, reservoirs and other characteristics of the local hydro systems. The transmission system between the areas are described by the transmission capacity, losses and a transmission fee. An example of a system model is illustrated in Figure 2.6. Note that this example is not the model setup used in this thesis. The model setup is explained in chapter 3.1. [12][16]

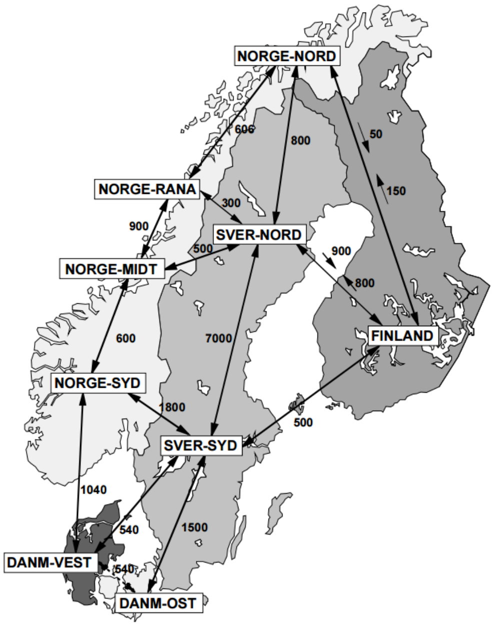

Figure 2.6: *An example of a model of the Nordic power system consisting of several areas in the EMPS model. [12]*

Each area is described by components such as demand, hydropower, thermal power, wind and solar power, but all areas does not necessarily contain all the components. An illustration of an aggregate area with all the components is shown in Figure 2.7. [12][16]

Hydropower

Hydropower is described by a hydropower module consisting of a power station and a reservoir with storable and non-storable inflow. An illustration of a hydropower module is shown in Figure 2.8. Different endpoints could be defined for spillage, bypass and plant discharge. The reservoir is given by its volume [Mm^3]. For the power plant the discharge capacity [m^3] and energy equivalent [kWh/m^3] must be defined. The energy equivalent describes how much energy is stored in each m^3 of water in the reservoirs. The inflow is defined either as storable or non-storable and is given as a yearly volume [Mm^3] and a series giving the variations through the year. Non-storable inflow must be used directly, and if this volume exceeds the discharge capacity, it will result in spillage. [12][16]

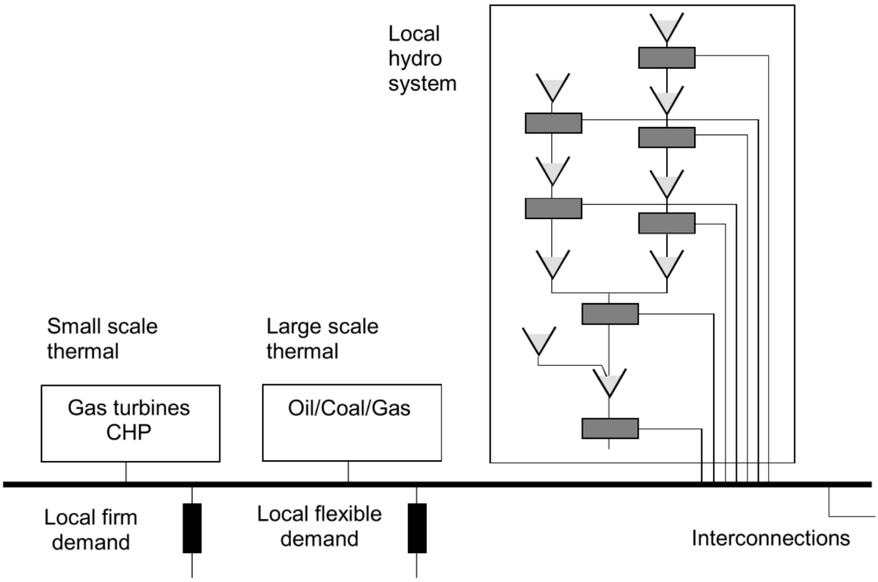

Figure 2.7: *The aggregate area model with the describing components supply and demand. [12][16]*

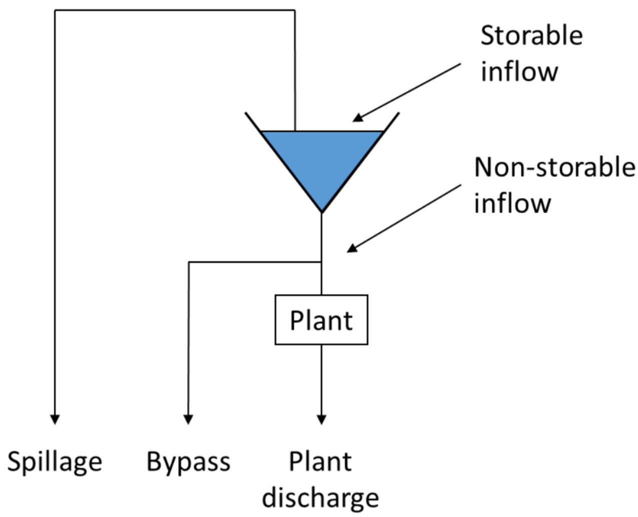

Figure 2.8: *Standard hydro power module. [12]*

Thermal power

Thermal generation units are defined by production capacity and the variable costs, e.g. fuel costs. The expected availability of thermal units may be modelled by constructing an expected incremental cost curve (EIC) for each time step. Some fossil-fuelled plants could be contractually or otherwise bound to receiving a specified inflow of fuel. These could either be specified by a specified energy volume per week into the power system, or as a hydro module, treating the gas contract as inflow and gas storage as a reservoir. [15][16]

Wind power and solar power

Wind power is given by historical or simulated data for wind speed for specified geographical areas. It is given as a energy series with a fixed hourly value in the model. Solar power is given in a similar way as wind power, with either historical data or simulations for PV-productions for every hour through the year. [12][16]

Demand

Load demand can be divided in two categories: Fixed load demand, which has limited or no price elasticity, and price elastic load demand.[16]

Fixed load demand is modelled as specified energy demand week by week, and the variation within the week is modelled with a certain load for the given price periods. Firm demand can be made dependent on temperature and price, by using a linear or exponential function to describe the relation between price level and consumption quantity. [12][16]

Price elastic load demand is defined as a specified energy use in GWh and a cost of disconnection. When the marginal costs exceed the price level, the load is disconnected. One can distinguish between short and long term price elasticity. [12][16]

Power exchange

The power exchange between interconnected systems is modelled as contractually fixed exchange or spot exchange. When the power exchange is modelled as fixed exchange, import and export are modelled as contract used in certain periods. These are specified by prices and exchange volume. Spot exchange is a result of the market clearance process and is given by the power price, transmission capacity, losses and fees. [12][16]

2.3.2 The strategy phase

In the strategy phase, the expected marginal water values are computed as a function of time and reservoir level, by the use of stochastic dynamic programming (SDP). To limit the computational burden, all plants are aggregated into one aggregated plant and all reservoirs in one aggregate reservoir within each area. [12][15][16]

Energy inflow to aggregate system

In the aggregate model the distribution of storable and non-storable inflow has to be modelled in a special way in order to obtain realistic results. The aggregated large reservoir would not represent situations where one or some of the real reservoirs would flood and lead to spillage. To take this in to consideration, the non-storable and storable inflow are calculated as shown below [12][16]:

Non-storable inflow =

  Generation due to non-storable inflow to the power stations

$+$ Generation due to minimum discharge and/or bypass constraints

$+$ Generation necessary to avoid spillage

$-$ Energy used for pumping to avoid spillage

Storable inflow =

  Sum production (including time-of-use purchase contracts)

$-$ Energy used for pumping

$+$ Increase (or $-$ decrease) in reservoir volume

Water values

When finding the optimal operation of a hydro power system, the key element is to minimize the operational costs of every week in the period of analysis. The mathematical description for total operational dependent costs is given in equation 2.1. The function $J(x, k)$ represents the value of the expected total operational costs from the present point in time at the start of week k, where x represents the reservoir level and k is the week number. The total operational costs is equal to the costs of change in reservoir level plus all the variable costs. [12][16]

$$J(x,k) = S(x,N) + \sum_{i=k}^{N} L(x,u,i) = L(x,u,k) + J(x,k+1) \tag{2.1}$$

where:

$S(x,N)$ = The cost of the change in reservoir, i.e. the value of the start reservoir minus the value of the remaining storage content, as function of the reservoir level, x, at the end of the period, time step N.

$L(x,u,i)$ = Operation dependent costs when going from period i to $i+1$. $L(x,u,i)$ includes costs of purchasing power, costs of own thermal power generation, costs linked to curtailment of firm power and income from spot power sales.

u = Energy drawn from own reservoir to produce a certain quantity of power p. $u = f(p)$

The amount of energy u drawn from the reservoir impacts the variable costs, and therefore the challenge is to find the u that results in lowest costs [12]. This gives [12]:

$$min_u J = min_u L(x,u,k) + J(x,k+1) \implies \frac{dJ}{du} = 0 \tag{2.2}$$

where:

$\frac{\partial L}{\partial u_k}$ = Marginal operation dependent cost linked to purchase, sale, curtailment, etc.

$\frac{\partial J}{\partial x_k + 1}$ = Marginal total future dependent cost with regard to the reservoir level, i.e. the margianl water value at time $k+1$.

To achieve optimal handling of the hydropower for each week, water values are used as resource cost of hydropower. In other words, the optimal use is when the purchase and sales marginal costs are equal to the water value. In Figure 2.9 the optimal decision at the reservoir level M for a given inflow is illustrated, where it is assumed that the water value is known by the end of the week. [12][16]

The inflow is not known, and it is necessary to take this uncertainty into account. This is done by finding the water value by calculating the water value for different inflow scenarios, where each inflow occurs with a certain probability. Equation 2.3 shows the resulting and optimal water value. [12][16]

$$\kappa_0 = \sum_{i=1}^{n} \kappa_i k_i \tag{2.3}$$

where:

κ_0 = The resulting water value
κ_i = The water value for inflow scenario i
k_i = The probability of the inflow scenario to occur

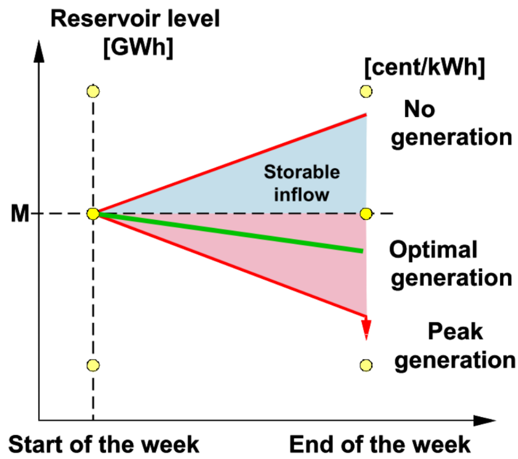

Figure 2.9: *Example of optimal decision based on the water value. [12]*

Calibration

When calculating the water values, exchange with other areas must be taken into account. This is done in the calibration of the model, where the objective is to minimize the total costs or maximize the social surplus. Mainly the reservoir handling and changes in social surplus are considered to obtain this. [12][16]

Important signals for the reservoirs are:

- Distribution of the remaining reservoir before the spring culmination
- Emptying of large reservoirs with a high degree of regulation (size of reservoir/mean annual inflow) in dry years
- Filling up of reservoirs in the autumn

The calibration factors used in this process are listed below and shortly described [12][16]:

Feedback factor - modification of firm demand

The size of firm demand greatly impacts the water values and simulated reservoir handling. The factor models the feedback from demand in other areas and controls how much firm demand that is considered during the water value calculations. Therefore, it has an impact on the level of the iso price curves and the curves describing the reservoir handling. Figure 2.10 shows an example of computed water values as a function of total reservoir in GWh and time of the year, and is called iso price curves.

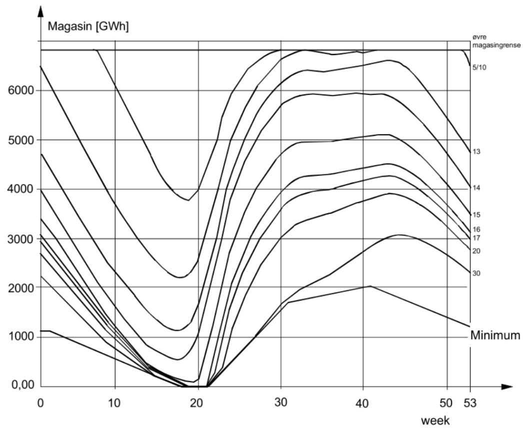

Figure 2.10: *Example of iso price curves for selected water values. [12]*

Form factor - annual distribution of firm demand

The form factor describes the annual distribution of demand over one year in one area compared with the interconnected system's annual distribution. A value of 1.0 results in the same distribution as the interconnected system. A larger value implies higher demand during winter and lower during the summer. Whereas a smaller value implies the opposite.

Elasticity factor of price flexible demand

This factor affects the quantity that is available at each price level of the demand curve, i.e. the elasticity of the demand curve. Reducing the factor makes the demand curve steeper. This results in closer iso price curves and therefore the result space for the reservoir handling is reduced.

2.3.3 The simulation phase

In the simulation phase, the goal is to find the system operation state for different inflow scenarios, and is based on the water value calculations in the strategy phase. The simulation phase has two stages. In the first stage, an area optimization is done, where the costs, losses, capacities and constraints are taken into account in finding the optimal decision. At this stage the market clearance is done, which is the intersection point of the supply and demand curve. [12][16]

In the second stage, a detailed reservoir drawdown strategy is used to distribute the optimal total production between the available plants. If the production decided in the area optimization is not obtainable within the constraints at the detailed level, a new area optimization is run and modified. Figure 2.11 illustrates the stages of the simulation process. [12][16]

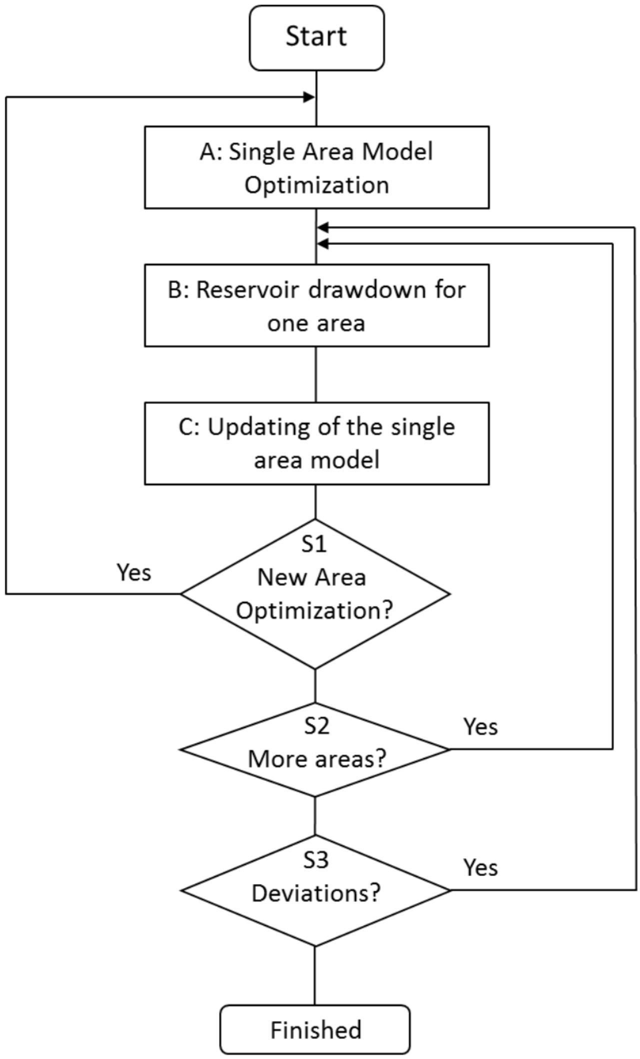

Figure 2.11: *The steps of the simulation phase in the EMPS model. [12]*

3 | Model setup and cases

3.1 Model setup

The model setup used in this thesis is developed by the Norwegian Water Resources and Energy Directorate (NVE). It is chosen a model setup for 2030, because the objective of this thesis is to analyze the impact of a large implementation of ZEBs in the Norwegian power system in order to prepare for the consequences of such a large change. The 2030 model setup is closer to a power system with a large share of ZEBs, compared with e.g. today's model setup, with the projections on installed capacity including an increasing share of renewables, new connections and increased share of electric vehicles (EVs).

The model setup consists of 13 areas in Norway, four in Sweden, two in Denmark and one in Finland. Figure 3.1 shows the areas in Norway in the 2030 model. The areas in the other Nordic countries coincides with the price areas depicted in Figure 3.2. In the model the simualtion period from 1981 to 2010. This mean that hydrological data for this period is used as inflow scenarios, which gives a range of outcomes for the modelled 2030 power system. In this model, each week has 56 different price periods, which gives a resolution of 3 hours per price period. This is a rather high resolution compared with earlier use of the EMPS model, and is necessary due to need of a more detailed description of the demand, a higher share of intermittent power production and allows power exchange at a higher resolution.

Production

By 2030, there will be changes in power production in the Nordic power system compared to today's power system. The assumptions on changes in installed capacity in this model setup is done by the NVE, and is based on projections from Statnett, the European Commission, energy companies, consultancy companies, and NVE's own assessments. Examples of significant changes are the shut down of some of nuclear plants in Sweden within 2030. In this model setup the following nuclear plants are shut down: Oskarshamn 1&2 and Ringhals 1&2, which reduced the capacity of approximately 2930 MW [18][19]. Finland, on the other hand, is

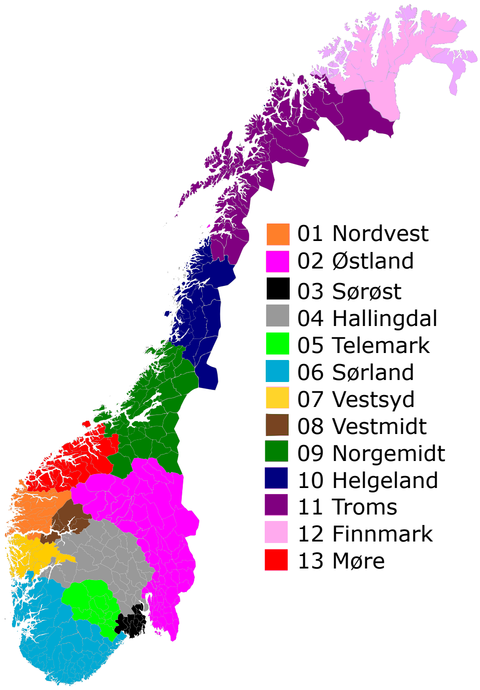

Figure 3.1: *EMPS-regions in Norway in the 2030-model*

planning to build one new nuclear plant, which gives an increase of 1600 MW of installed capacity [20]. The share of wind is expected to increase in all Nordic countries, but Denmark and Sweden are expected to have the largest growth. Even with these changes, hydropower and thermal power, including nuclear power, will have a dominant part in the Nordic power system.

Exchange

The Nordic countries are connected to each other with power cables and lines. By 2030, there will be built several connections within countries, between the Nordic countries and to other countries. This model setup includes the North Sea Link cable to the UK and the NordLink cable to Germany from Norway, both with a planned capacity of 1400 MW. In total there are 11 connections from the Nordic countries, in this model setup, to the following neighbouring countries: the United Kingdom, the Netherlands, Germany, Poland, Lithuania, Estonia and Russia. Figure 3.2 shows a simplified map over the price areas and connections within and from the Nordic countries used in the model setup.

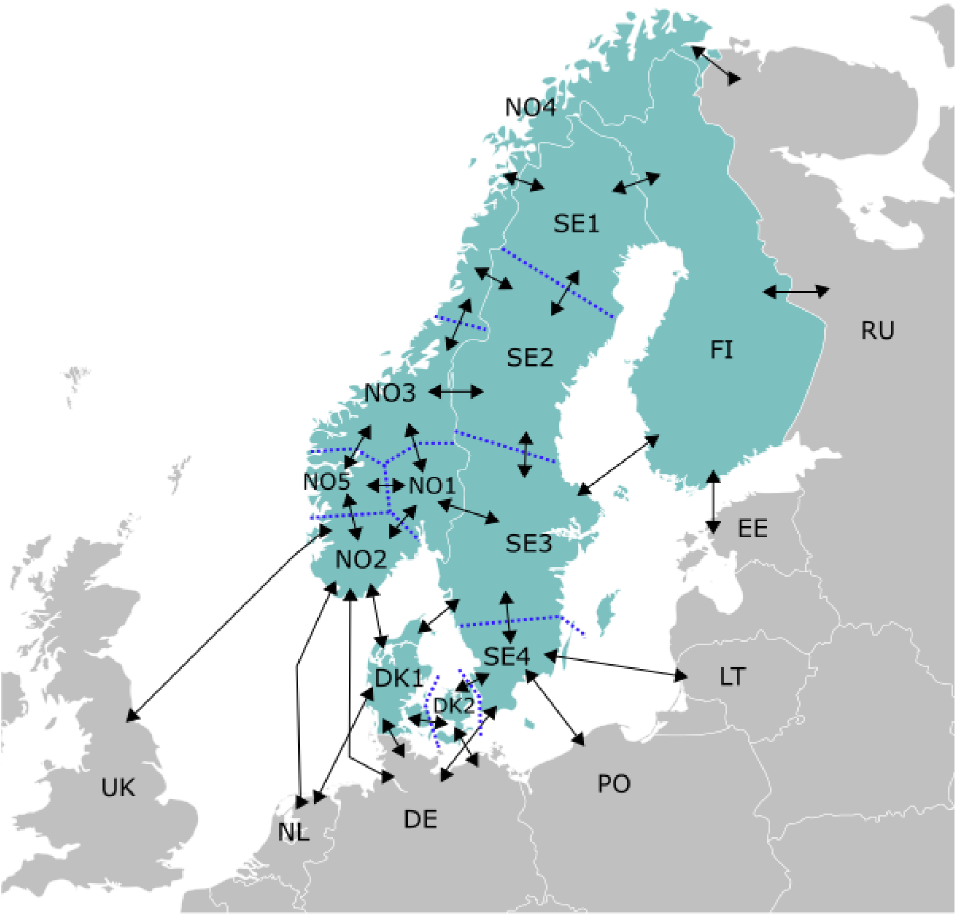

Figure 3.2: *A simplified map showing price areas and connections within and from the Nordic countries in the model setup.*

Demand

The demand, consists mostly of demand from the building stock and the industry. The large implementation of ZEBs affects the demand significantly. The higher resolution, with 56 price periods in each week, allows a very detailed load-profile. The input load-profile for the building stock is given for each hour, which is merged together in 3-hour price periods during the simulations in the EMPS model.

In this model setup, the demand for the building stock in Norway is described in another way than usual. The load curve is modelled in two parts. In the first part, a load equal to the maximum load experienced throughout the 30-year-period, is given. In the second part power production (negative load), is added to the system. The difference between maximum load and the power production is the resulting load-profile. Figure 3.3 depicts an example of a defining maximum load (which occurs in hour 123) and the added power production (green, shaded area). Both parts are given in the same EMPS area, and the resulting output is the load profile for this week which is the blue, solid filled area in Figure 3.3. The process is repeated for every week in the entire 30-year-period, but still using the global maxima load as the defining peak. Figure 3.6 in subsection 3.2, where the demand is explained more in detail, shows the large variations of demand throughout the 30-year-period. The global maxima can be seen in the beginning of the year.

The reason for described the demand is this way is to achieve the desired, detailed load profile which also maintains the differences between the years. The usual way of describing demand gives a repeated load profile equal for each year, with a weekly temperature correction. For this detailed load profile the temperature correction is done in a higher resolution. This way of describing the demand is only done for the building stock, including ZEBs and existing buildings, in Norway.

The remaining demand, mostly industry and some from transportation (EVs) in Norway and the demand in the other Nordic countries, is done in the usual way with a repeated load profile for each year, with weekly temperature corrections.

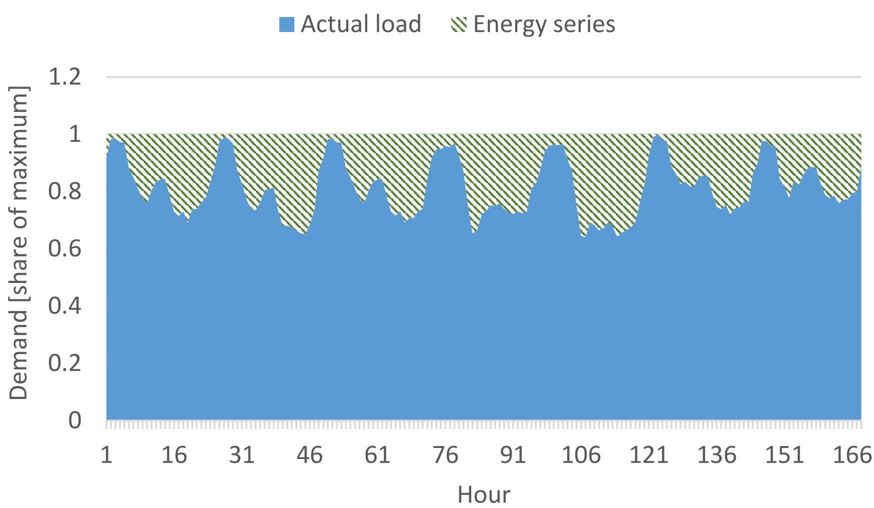

Figure 3.3: *The principle of how the demand is modelled. This is the week with the global maxima for the entire simulation period.*

Other input

In the EMPS-areas for the neighbouring countries, price series are given. Figure 3.4 presents these price series and are projected by NVE. They are based on the expected development of the power system in these countries, but are very difficult to predict. There are large uncertainties related to e.g. the growth of intermittent renewable energy, price of CO2 and different fuels and the reduction of fossil and nuclear power. These price series has major effect on determining the flow direction, between the countries and consequently this affects the prices in the Nordic region.

In this model setup, the following prices are assumed for CO2 and selected fuels:

- Price of CO2: 20.00 NOKøre/kg
- Price of coal: 10.88 NOKøre/kWh
- Price of gas: 25.20 NOKøre/kWh

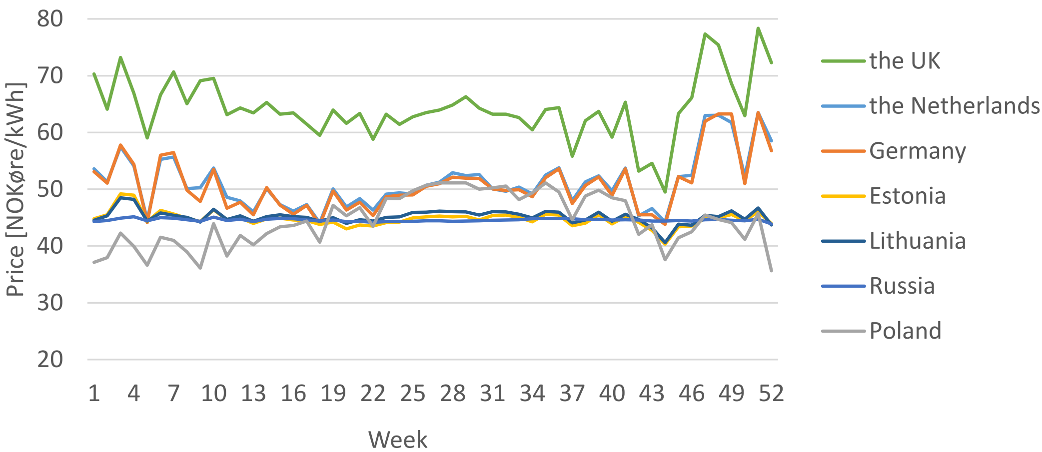

Figure 3.4: *Price series for the neighbouring countries of the Nordic countries.*

3.2 Model cases

This thesis analyses six model cases. The cases differ from each other by the share of ZEB, choice of heating technology, demand and PV-production. An overview of the cases can be seen in table 3.1. The different cases is described in the following paragraph. The PV-production, demand and heating technology are described in the following subsections.

Table 3.1: *An overview of the model cases*

Model cases	Share of ZEB	PV-production	Reduced demand	Heating technology
BAU	0	No	No	Mix
SUN	0	Yes	No	Mix
PAS	0[1]	No	Yes	Heat pumps
DIR	50 %	Yes	Yes	Direct electricity
HPU	50 %	Yes	Yes	Heat pumps
OTH	50 %	Yes	Yes	Other sources

The first case is the ”business as usual” (BAU) case, which is the reference case where a ”normal” development of the building stock is assumed based on the current policies for energy efficiency and heating technology.

Case PAS that is equal to the demand in case HPU, but there are no on-site PV-production, giving a building stock consisting of 50 % passive buildings.

In case SUN, the demand is the same as in case BAU, but there is a PV-production equal to the PV-production in the ZEB-cases. The purpose of analyzing these two cases in addition to the ZEB-cases, is to look at the effect of only reducing demand and only introducing PV-production.

Then there are three ZEB-cases where 50 % percent of the building stock are ZEBs. The three cases have different heating technology. In the first case, DIR, all heat demand is based on direct electricity heating or electric boilers. In the second case, HPU, heat pumps are the source of heating, while in the third ZEB-case, OTH, other sources such as biomass or district heating covers the heat demand. In these three ZEB-cases, there is also an on-site power production which is assumed to be PV-production. The annual production is equal to the electric specific demand in the ZEBs. In each ZEB-case there is chosen only one type of heating technology. It is not likely that a large implementation of ZEB, will only choose one kind of heating technology, but with this choice provides a larger range of possible outcomes and test the system.

1. Case PAS consist of 50 % passive buildings in the building stock

Demand and heating technology

The data for the demand in the building stock is provided by PhD-student Karen Byskov Lindberg [21][22], and is partially based on the work done in the project thesis [23]. The demand was given for five regions in Norway, which had to be customized to the EMPS-regions and was based on the earlier distribution of buildings in each EMPS-region in similar model setups provided by NVE. In Figure 3.5 the daily demand in EMPS-region Ostland is shown. The values in the weekend are lower than the weekdays seen as dips in the figure, which is the cause of the weekly reduction of demand that can be seen in the figure.

For the existing buildings there are assumed combinations of heating technology, based on [24][25] and NVEs own assessments, and existing energy efficiency policies.

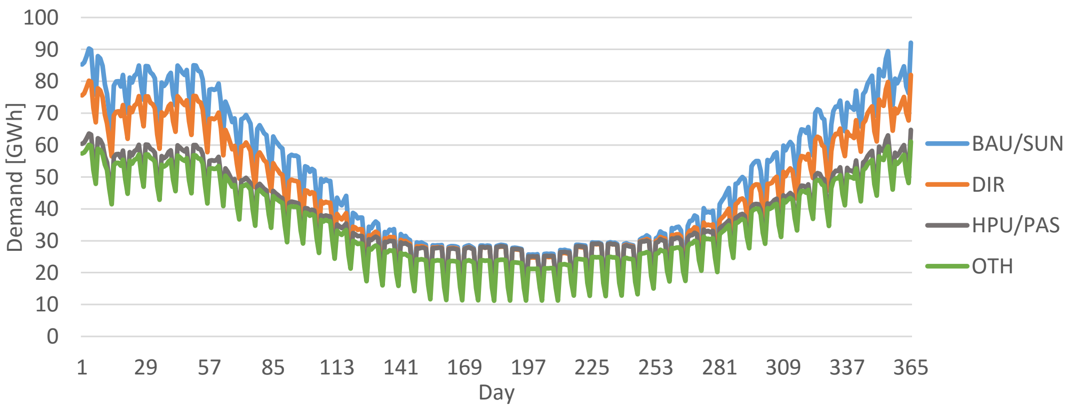

Figure 3.5: *Average daily demand in EMPS-region 02 Ostland for all cases for normal climate conditions.*

In 2030, an increase in electric vehicles (EVs) is expected. In this model setup it is expected that 50 % of a total 3 million vehicles are electric. Each car is assumed to drive on average 12 000 km, and has an electricity use of 0.2 kWh/km. These assumptions is done by the NVE. With these assumptions the yearly demand from EVs is roughly 3.7 TWh. Load profiles for EV-charging has been provided by NVE and can be seen in figure A.1 in appendix A. The load profile is equal for all days. This daily profile is based on the assumption of a share between home, work and fast charging of 65 %, 25 % and 10 %. The maximum load is at 574 MW and occurs during night at 1 a.m., while the minimum load is at 283 MW in the early morning at 5 a.m.

In Table 3.2 input demand (excluding electric boilers) is shown. NVE provides the assumed demand from the industry in 2030. Combined with the EV, this gives a demand of 59.4 TWh for all cases. However, there could be changes in demand during simulation due to price sensitivity of the energy-intensive industry.

Table 3.2: *Input demand from buildings, industry, EV and total demand*

Model cases	**BAU**	**SUN**	**PAS**	**DIR**	**HPU**	**OTH**
ZEB-buildings	-	-	20.9	31.0	20.9	16.9
Existing buildings	77.4	77.4	40.2	40.1	40.2	40.2
Industry and EVs	59.4	59.4	59.4	59.4	59.4	59.4
Total electricity demand	136.8	136.8	120.5	130.5	120.5	116.5

The grid losses are accounted for in the input demand.

Figure 3.6 shows the range in demand for the model cases HPU and PAS for normal climate conditions for all the simulation years. The figure shows the span in demand, due to the temperature differences. This large variations from year to year, and the detailed level is the reason of modelling the demand in a different way than ususal, as explained earlier.

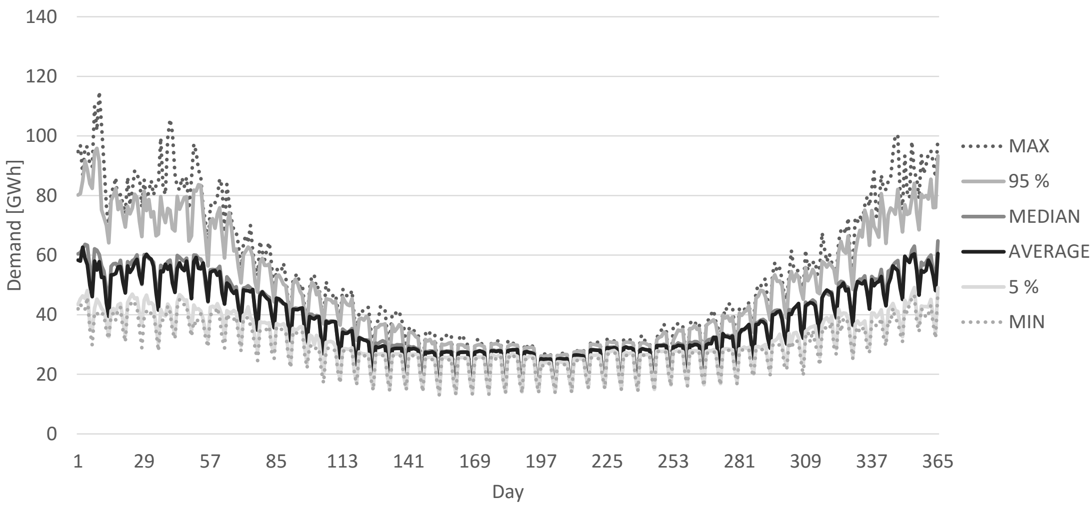

Figure 3.6: *The range of daily demand i EMPS-region 02 Ostland for model case HPU and PAS for normal climate conditions in the simulation years.*

PV-production

In this thesis the on-site power production for the ZEBs are assumed to be PV. From the demand data given from PhD-student Karen Byskov Lindberg, the PV-production was found. The data received was measurements from only one year. In consequence, the PV-production in each price period is equal for each simulation year. The PV-production assumes to cover the electric specific demand, which in Norway is equal to 16.9 TWh for all ZEB-cases. Figure 3.7 shows the weekly PV-production in EMPS-area Ostland. The yearly production is 6003 GWh. Table 3.3 shows the annual on-site PV-production in each EMPS-area in Norway.

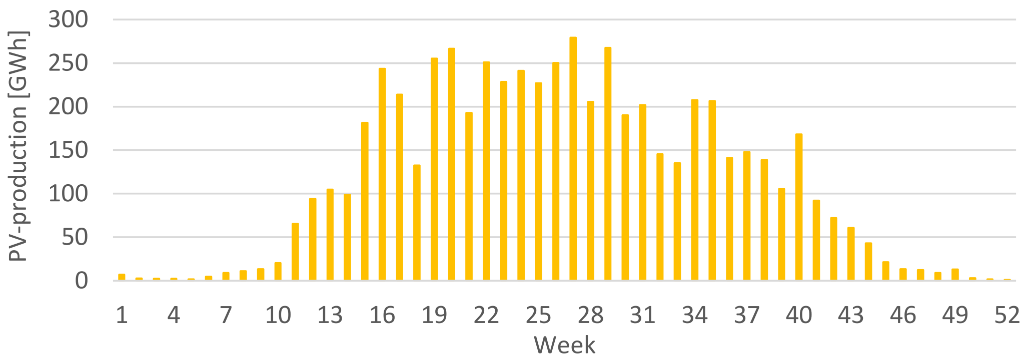

Figure 3.7: *Weekly PV-production in EMPS-area 02 Ostland. Yearly production: 6003 GWh.*

Table 3.3: *PV-production in the EMPS-areas in Norway*

EMPS area	**PV-production [GWh]**
01 Nordvest	270
02 Ostland	6003
03 Sorost	1181
04 Hallingdal	1130
05 Telemark	169
06 Sorland	2732
07 Vestsyd	1417
08 Vestmidt	84
09 Norgemidt	1450
10 Helgeland	304
11 Troms	1046
12 Finnmark	236
13 Moere	860

Due to low quality on the insolation-measurements in Norway [26], the PV-production is simulated for a normal climatic year [27]. Therefore, the PV-production is equal for every year in the simulation period. Ideally, there should be an energy series for PV-production for every series for inflow and temperature. However, measurements done in Kessel in Germany indicates that the annual variations is approximately 8

% [28]. Therefore, the absence of annual variations of PV-productions are considered as satisfactory for this thesis.

4 | Results and discussion

This chapter presents and discusses the results from running the EMPS-model with the earlier described six cases. Introducing ZEB in the power system lowers electric demand for heating in the winter and increases power production in the summer. Both of these effects lead to an increased access of power in Norway. It is therefore interesting to analyze the effect on power balance, CO_2 emissions, reservoir handling, prices and exchange.

4.1 Power balance

Table 4.1 shows an overview of the production, demand and power balance in the Nordic countries. The results for cases DIR and OTH are found in Table B.1 in Appendix B. The overall picture is an increase of the positive power balance in the Norwegian power system, while there is a decrease in the other Nordic countries. The demand is in all cases higher than the input demand. This is mostly demand from electric boilers.

The power balance in total for the Nordic countries increases from 36.4 TWh in the BAU case to 59.6 TWh in the HPU case. In OTH the surplus is 61.8 TWh. The change from BAU to HPU is due to both decrease in demand and an increase in power production from solar power.

The power balance in Norway spans from a surplus of 10 TWh in BAU to 47.4 TWh in OTH, while Sweden and Denmark have a small decrease of 3.2 TWh and 1.6 TWh respectively. However, Denmark has a positive power balance in case BAU, and negative balance in cases HPU and OTH and barely positive in case DIR. In Finland, the balance decreases from 11 TWh to 3.9 TWh in OTH.

The production changes the most in Norway because of the introduction of 16.8 TWh of PV-production in case SUN and the ZEB-cases. The production in Sweden hardly changes, while there is a small change in Denmark and Finland. In Denmark production is reduced by 1.4 TWh, whilst in Finland the reduction is 4.6 TWh. The reduction takes place in thermal power plants. The reductions in thermal production are alot smaller than the increased PV-production. It could be expected

Table 4.1: *Power balance in Nordic countries for cases BAU,SUN, PAS and HPU.*

Case BAU	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	151.1	157.8	38.3	106.0	453.2
Demand [TWh]	141.1	143.6	37.2	95.0	416.9
Balance	10.0	14.2	1.1	11.0	36.4
Case SUN	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	168.9	157.9	37.7	104.1	468.7
Demand [TWh]	141.5	144.8	37.2	95.8	419.4
Balance	27.4	13.1	0.5	8.3	49.3
Case PAS	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	151.2	157.7	37.8	104.7	451.4
Demand [TWh]	124.6	144.7	37.2	95.7	402.3
Balance	26.6	13	0.6	8.9	49.1
Case HPU	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	168.6	157.9	36.9	101.4	464.8
Demand [TWh]	125.0	146.3	37.2	96.7	405.2
Balance	43.7	11.6	-0.4	4.7	59.6

that the PV-production could remove more of the thermal production. Possible explanations to this could be limited exchange capacity, because the production from renewables are intermittent or that the fact that solar power produces most in the late spring, summer and early autumn. Also, thermal power plants could be CHP - combined heat and power - plants, where the heating demand determine whether they produce or not.

The demand in Norway is slightly higher than the input demand, because of the demand from electric boilers which is price dependent. Otherwise the demand is not changed, and this shows that the Norwegian industry demand is not greatly affected by the changes in the power system. This is as expected, since most of the industry in Norway is not very flexible [29]. However, in Sweden the industry increases the demand with 2.7 TWh. From the results, both reductions and increases in demand in industry can be found, as the results in Table 4.2 shows. The increased demand in Sweden and Finland is due to lowered demand reduction, since there are fewer hours with high prices. In Sweden and Finland there are a relatively high share of forest-based industry, which is more flexible du to prices [29]. The increase in Finland of 1.7 TWh are due to the same reasons as in Sweden. In Denmark there are no changes in demand.

Table 4.2: *Demand reductions and increases in the industry in Sweden due to prices for model cases BAU and HPU*

Case	**Reductions**	**Increases**
BAU	7.46 TWh	1.25 TWh
HPU	4.73 TWh	1.15 TWh

A comparison of the cases SUN and PAS, shows that the difference inn power balance is very small. Case SUN has an increase in production equivalent to the increase in demand in case PAS in comparison with case BAU. However, the increase in demand is mostly in the winter, because of the need of heating, while the increase in production is during the late spring, summer and early autumn. An increase in production in case SUN to cover the demand in winter could be expected, but it seems that the system is able to store the surplus during the summer, so it can be spent in the winter. The reservoir handling is discussed further in Chapter 4.3.

A more detailed distribution of production is presented in Figure 4.1 and 4.2. This is the production by source in the selected weeks 3 and 28. These are average values for all simulation years, which gives a smoothing effect on the intermittent power production, especially wind power. Wind power has in reality a much larger variation. As explained in Chapter 3.2, the PV-production is equal for every and simulated for a normal climatic year in Norway. The effect of this, is a smoother PV-production.

The obvious difference between winter and summer is the PV-production. Eventhough the demand is higher in the winter, the production is highest in the summer with up to 9.5 GW PV-production in an hour. The wind power production is slightly higher in the winter, up to 2.1 GW in an hour, while in summer up to 1.4 GW in a hour. The power production from nuclear and other thermal power plants is slightly lower during the summer. The hydropower is also lower and with little variations throughout the day. However, we see an increase in the evening, when the PV-production is lower.

The comparison between Figure 4.2 and 4.3 shows an increase of the power production in case HPU from 16 GWh to 23.5 GWh. Nuclear power and other thermal power except coal is at the same level. In addition it can be seen that the hydropower production is higher in case BAU in order to cover the demand, and has a familiar daily profile with low production at night with an increase during the day. The production is lower in the weekend in case BAU, while the production is approximately the same for every day in the week in case HPU.

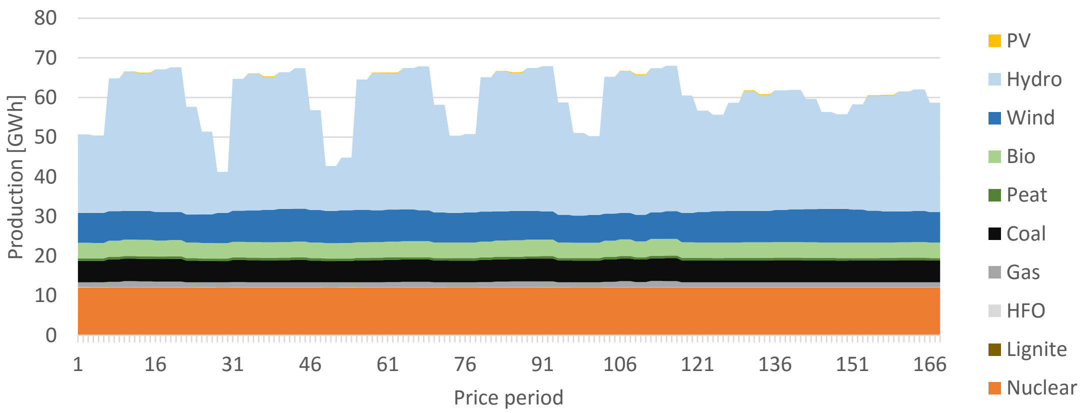

Figure 4.1: *Power production by source in week 3. Case HPU*

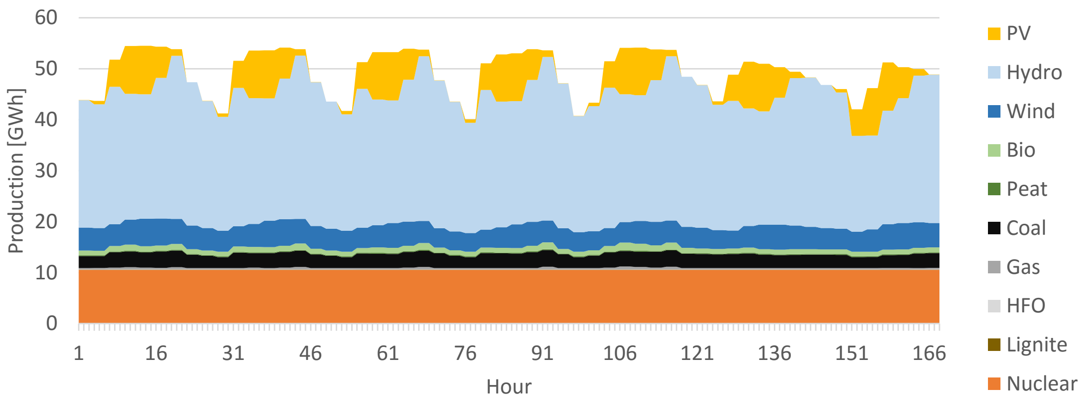

Figure 4.2: *Power production by source in week 28. Case HPU.*

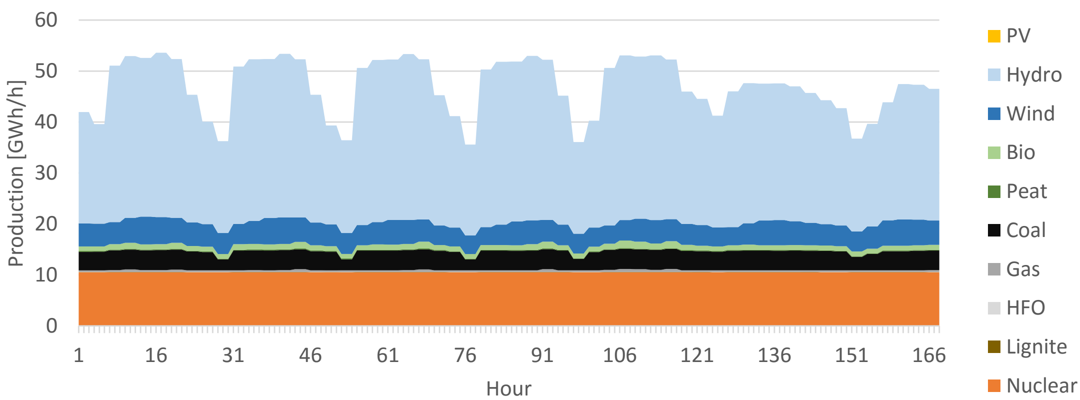

Figure 4.3: *Power production by source in week 28. Case BAU.*

4.2 CO_2 emissions

The changes of power production presented in previous chapter, shows a decrease in production in Denmark and Finland. Most of the reduction occur in fossil thermal production, and mainly in coal-fired power plants as Table 4.3 shows. Gas power plants only have minor changes, while the use of heavy fuel oil (HFO) is unchanged for all cases. The largest reductions of thermal production occur in the ZEB cases, and apply especially to the cases HPU and OTH.

The table also presents the resulting change of total CO_2 emissions from power production in the Nordic countries. The CO_2 emissions from the different sources can be seen in Table B.2 in Appendix B. Not surprisingly, the changes in CO_2 emissions correspond with the reductions in thermal production. The CO_2 emissions in case HPU reduces with 5.32 mill. tonnes compared with case BAU. Case SUN removes more coal-fired plants than case PAS.

The CO_2 emissions per kWh produced is 97.8 gCO_2/kWh for case BAU and 83.9 gCO_2/kWh for case HPU, which is a reduction of 15 %. Case SUN has a reduction of 8.2 %, while case PAS has a reduction of 3.2 % compared with case BAU.

Table 4.3: *Change of thermal production. Change in CO_2 emission within the Nordic system. CO_2 emissions per produced kWh within the Nordic countries.*

	BAU	SUN	PAS	DIR	HPU	OTH
Change of fossil thermal production [TWh/year]	-	-2.6	-1.9	-4.0	-6.1	-6.5
of which is coal	-	100 %	97 %	100 %	99 %	99 %
Change in CO_2 emissions [mill. tonnes]	-	-2.24	-1.60	-3.53	-5.32	-5.68
CO_2 emissions per kWh produced [gCO_2/kWh]	97.8	89.7	94.6	87.3	83.9	83.2

4.3 Reservoirs

The results for the average reservoir levels in Norway for all cases are presented in Figure 4.4. Here there is a clear difference between the cases with PV-production and the two cases without PV-production. For case HPU, the difference is between 6-11 percentage points compared to case BAU. The difference is highest in the spring and lowest in the autumn. As seen in Figure 3.7 in chapter 3.2, the PV-production has relatively high production in March and April. Because of increased production in the spring and the expectation of high PV-production later in the summer, the risk of emptying the reservoirs is lower. This allows a lower reservoir level in the spring. In addition, the reservoir level must be low in this period in order to have enough capacity to store the incoming inflow from snow melting during the late spring and summer and the rainfall in the autumn. This is important in order to avoid spillage. The typical inflow was shown in Figure 2.3 in Chapter 2.2. The PV-production reduces the prices so it is more profitable to produce other parts of the day and year. The results for prices are presented and discussed in Chapter 4.4.

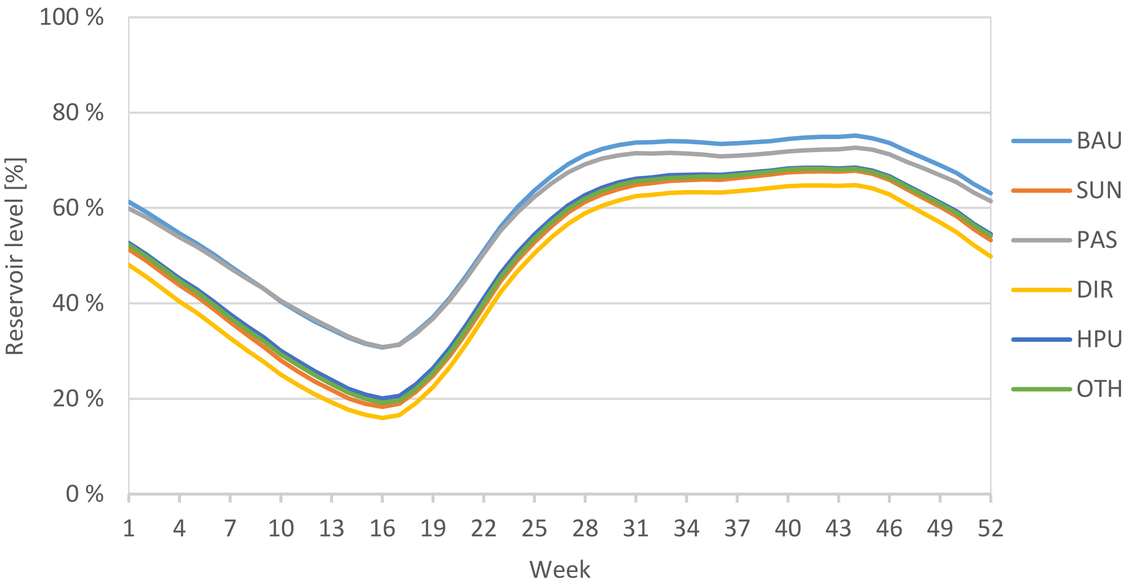

Figure 4.4: *Average reservoir level for all cases for Norway. Weekly values.*

In case DIR the reservoir level is slightly lower than the other cases with PV-production. This could be due to the calibration which was done automatically. The calibration and the calibration factors was explained in Chapter 2.3. However, there are also a lower reservoir level in the depletion season, and could be due to the higher demand.

Comparison of the cases BAU and PAS shows that there are no differences during the spring, but from late summer to winter there is a lower reservoir level for case PAS. The demand in case PAS is lower in the winter, which Figure 3.5 in Chapter 3.2 shows. This lowers the risk of rationing in the winter and more water can be used in the autumn.

The power balance is relatively similar for the cases PAS and SUN, where case PAS has 16.3 TWh lower demand in winter and case SUN has 16.9 TWh higher production in summer compared with case BAU. However, the reservoir handling is not the same. This shows that the increased production affects the reservoirs level more than the decreased demand. Also the the production is increased in the summer - reducing the reservoir level in the spring as discussed earlier, while the decreased demand is reduced most during the winter, and very little or nothing in the summer. It seems that decreased demand do not increase the risk of spillage as much as increased PV-production.

The Figures 4.5 and 4.6 show a more detalied description of the reservoir level. Results for the cases SUN, PAS, DIR and OTH can be seen in Figures C.1 to C.4 in Appendix C. During the spring, it can be seen that the span between minimum and maximum level is smaller in case HPU than for case BAU. The expected PV-production is more predictable than the snow melting which depends on the precipitation earlier in the year and previous years. In this model setup the PV-production is modelled deterministic and is equal for every year as described in Chapter 3.2. Measurements done in Kassel in Germany shows a annual variation of 8 % in the insolation [28], which gives a relative predictable annual produciton.

The minimum level are approximately the same in both cases. The risk of emptying the reservoir is too large if the reservoir level is lower. The increased PV-production does not change this.

During the late summer and autumn, the situation is the opposite, the span increases for case HPU. In addition the gap between respectively minimum and 5% percentile and maximum and 95% percentile increases. However, the maximum level is approximately the same. The risk of spillage is too large if the maximum level is higher. The risk of emptying the reservoir and spillage are important factors that do not change even though there are significant changes in production and demand.

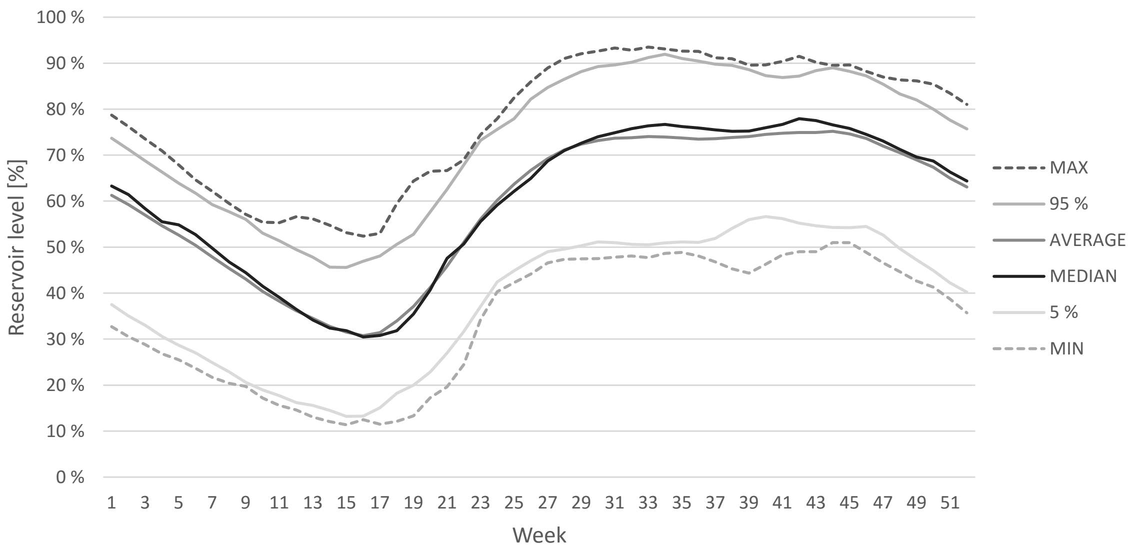

Figure 4.5: *Reservoir level for case BAU for Norway. Includes percentiles: 5% and 95%*

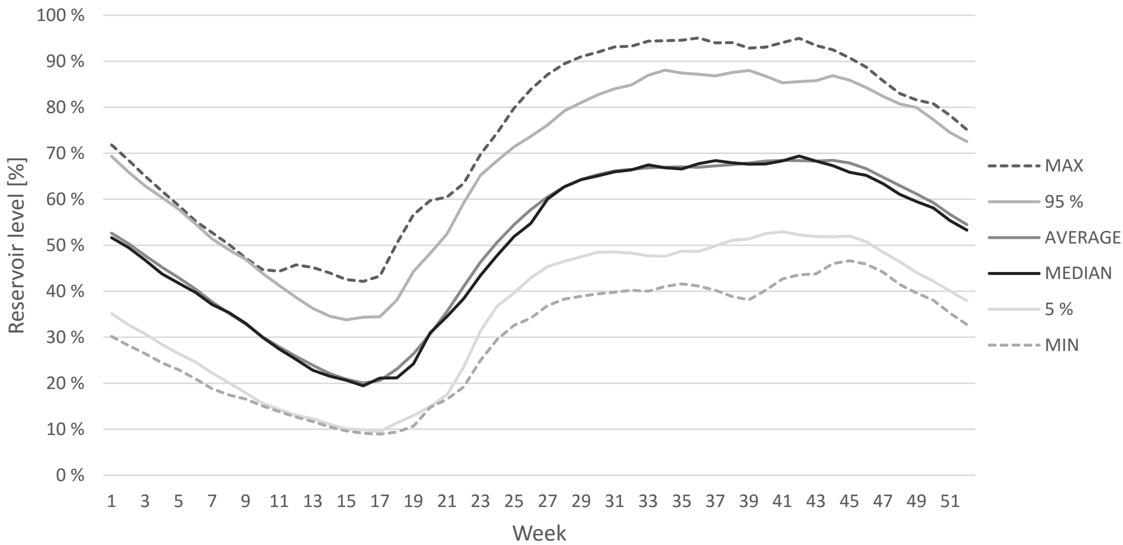

Figure 4.6: *Reservoir level for case HPU for Norway. Includes percentiles: 5% and 95%*

4.3.1 Spillage

As the results presented in Chapter 4.3 show, the maximum levels in the reservoir were approximately the same. The differences in spillage can be seen in Table 4.4. Every case has reduced spillage compared with case BAU. The difference between the cases BAU and HPU is 1.5 TWh. Figure 4.7 shows the weekly spillage for case BAU. Figures D.1 to D.5 in Appendix D show the results for the other cases. There are no major differences between the cases. In Figure 4.7 it can be seen that the minimum spillage is above zero during the summer, which means there will be spillage even in the driest years. The maximum and 95 % percentile are quite high during the summer and in some periods in the autumn.

Table 4.4: *Total spillage during a year in Norway for all cases. Average values.*

Case	**BAU**	**SUN**	**PAS**	**DIR**	**HPU**	**OTH**
Spillage [GWh]	14404	12618	13910	12378	12931	12890

Figure 4.8 show how large the variations can be from year to year. Note that the normal year is a median year, not an average year. We see that in the wet year the spillage occur in the summer, when the inflow is highest. The normal year has spillage early in the spring, late autumn and early winter, while in the dry year spillage is barely a problem, but is actually just above the normal year in some weeks.

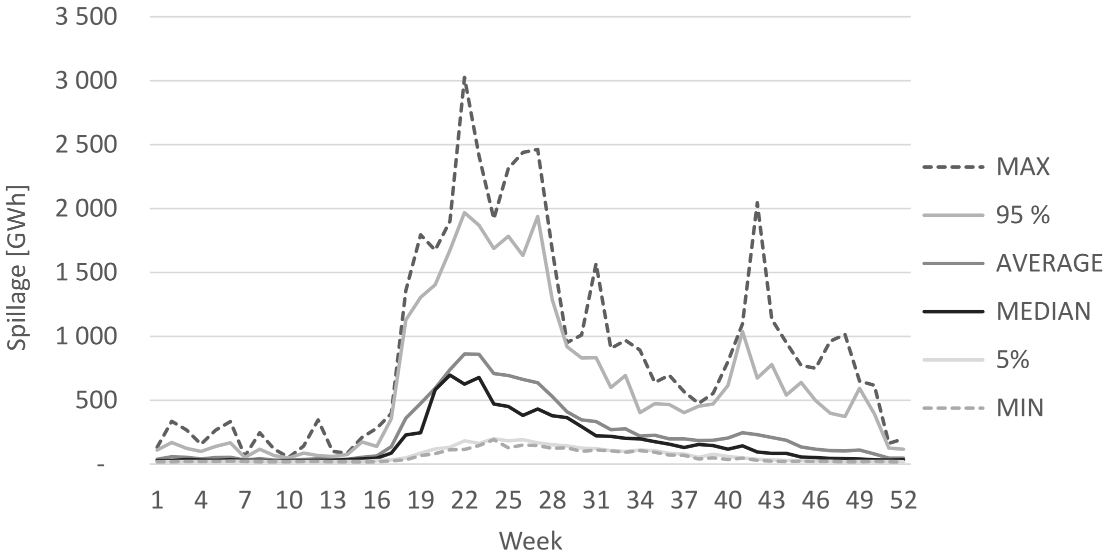

Figure 4.7: *Spillage for case BAU for Norway. Includes percentiles: 5% and 95%*

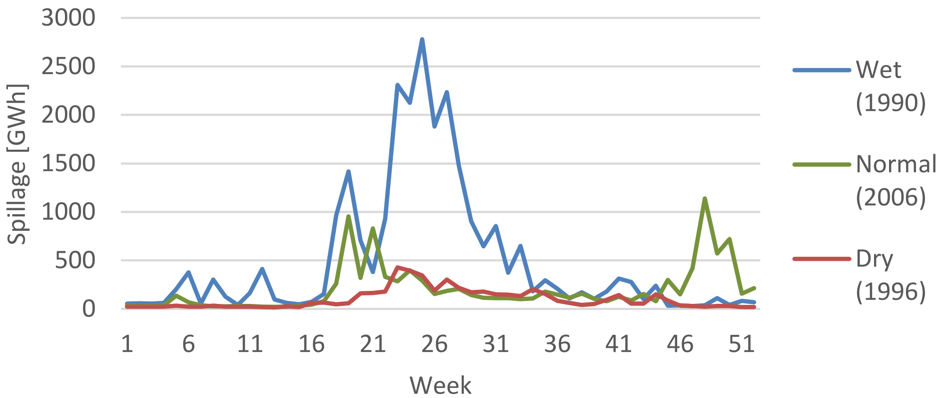

Figure 4.8: *Spillage for a normal (2006), wet (1990) and dry (1996) year in case BAU*

4.4 Prices

As explained in Chapter 2.2 there are five price areas in Norway. The price area NO2 has many connections to other countries: the UK, Germany, the Netherlands and Denmark, and have a high volume of reservoir capacity. Therefore, this area is interesting to analyze. Figure 4.9 shows the duration curve of the expected price in NO2 for each model case. In the high price field in the left of the figure, it can be seen that the cases BAU, SUN and DIR has a higher average price in some periods compared with cases PAS, HPU and OTH. This can be explained by the fact that the cases BAU, SUN and DIR have higher demand than the other cases, and will therefore experience a more strained system in some periods in the winter due to a high demand.

In the rest of periods there is an expected difference between the cases. The ZEB-cases have the lowest prices, while case BAU has the highest price. The price difference between case BAU and HPU is on average 7.3 NOKøre/kWh. An interesting observation is that the curve for case PAS has a flatter curve in comparison with the other cases, which is a result of lower demand during the winter and no PV-production during the summer. The cases with PV-production have a large share of prices below 40 NOKøre/kWh. The case OTH has clearly the highest share of an average price below this price with 1820 price periods below 40 NOkøre/kWh.

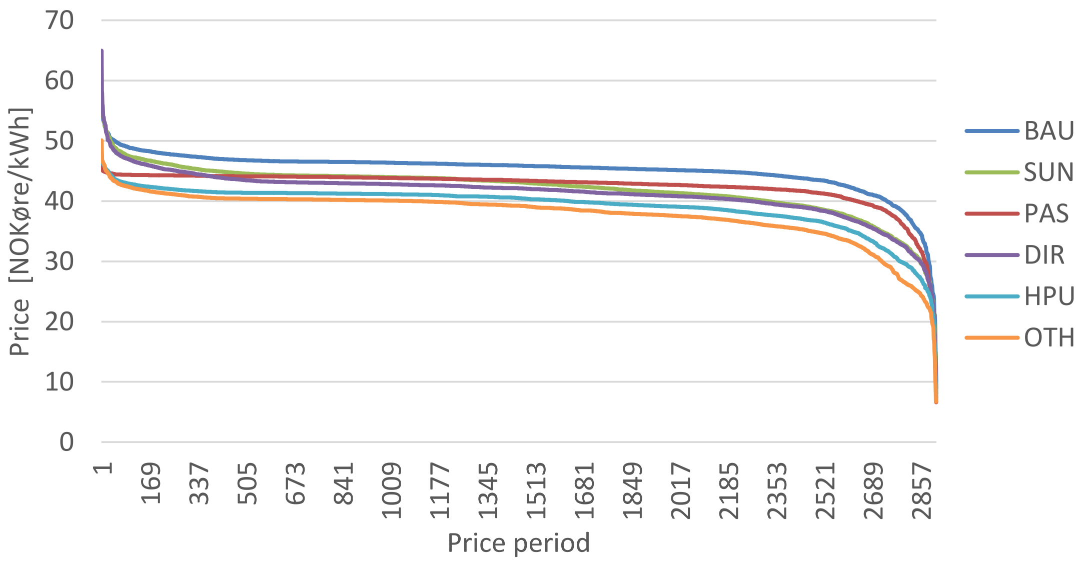

Figure 4.9: *Prices in price area NO2 for all cases. Average of all 30 scenario years.*

In Figures 4.10 to 4.13 the weekly prices for cases BAU, SUN, PAS and HPU are shown. Results for cases DIR and OTH are found in Figures E.1 and E.2 in Appendix E. For case BAU in Figure 4.10 the price is stable, but with a slightly increase from week 1 to week 16. As seen from the maximum and 95% percentile values there are some weeks during the simulation period that have increased prices in some periods. From week 16 the prices is reduced due to increased inflow from snow melting. The prices increase slowly from week 22-23 to end of the year, with some periods of reduced price in the autumn, because of the increased rainfall in autumn, and a high filling rate in the reservoirs. As the minimum and 5 % percentile show there are some periods during the summer with lower prices, presumably in years with low demand and a high reservoir levels.

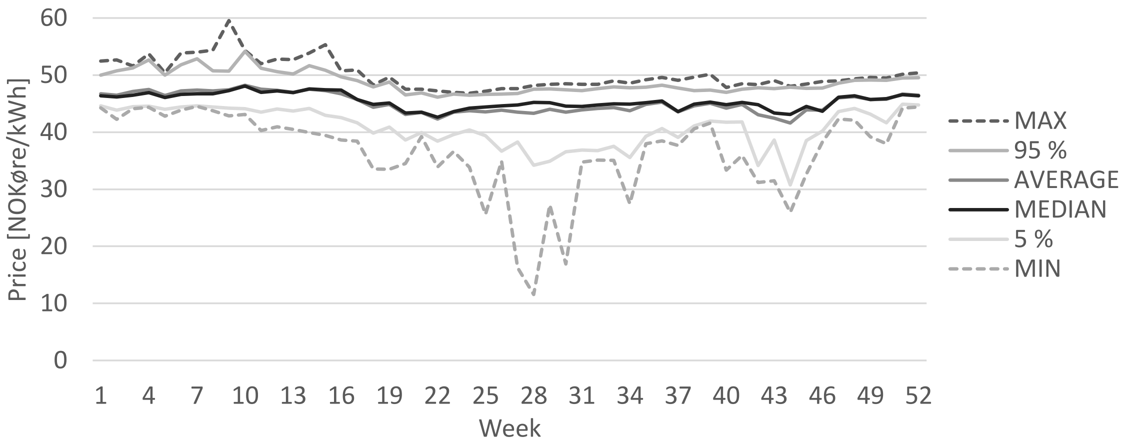

Figure 4.10: *Prices in price area NO2 for case BAU*

When introducing PV-prodcution to the system in case SUN, the prices are lowered. The average prices are in some periods down to and below 40 NOKøre/kWh. However, as the maximum curve and 95% percentile show, there are some periods in the winter that the price increases, probably due to higher demand in cold periods in some years. Also the price drop from week 16 is larger compared with case BAU, and as the minimum curve and 5% percentile show there is a price fall throughout the summer in some of the simulated years.

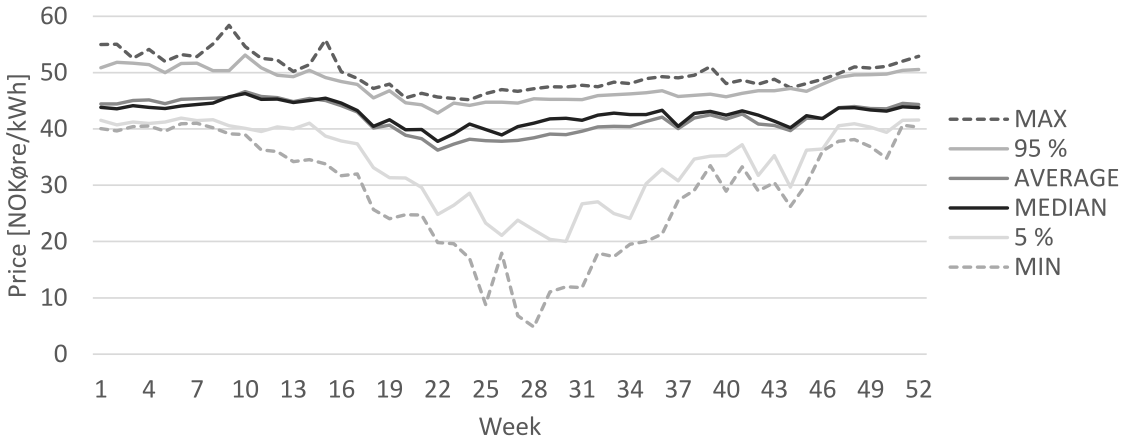

Figure 4.11: *Prices in price area NO2 for case SUN*

When just reducing the demand as in case PAS, the prices are lower and more stable throughout the year compared with case BAU. The average price has a decrease from week 16, but is much smaller. The maximum values have fewer peaks and there are more weeks with lower minimum prices in this case.

In case HPU, where both the demand is reduced and solar power is introduced, the effect is a reduced average price throughout the whole year. The average prices are close to 40 NOKøre/kWh, and lower in late spring, summer and in some periods in autumn. The price drop from week 16 is steeper compared with case BAU. As the minimum curve shows the weekly, average price is close to zero in some years, and is below 40 NOKøre/kWh for half of the years from week 18 to week 34.

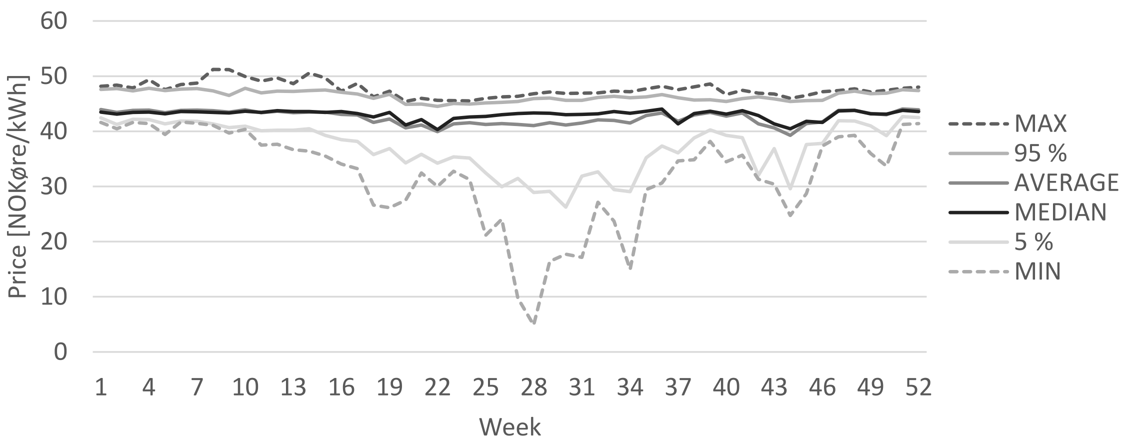

Figure 4.12: *Prices in price area NO2 for case PAS*

Drawing a parallel to the previous results for reservoir levels where there was a

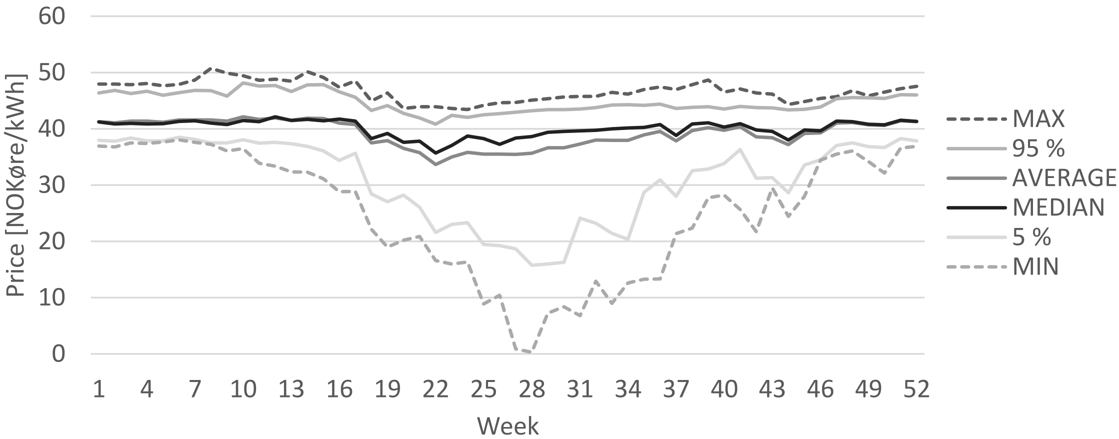

Figure 4.13: *Prices in price area NO2 for case HPU*

lower reservoir level for the ZEB-cases and the SUN-case, prices have an impact on the reservoir handling. Due to lower prices in the summer from the increased PV-production, it gets more profitable to save the water for the autumn and winter when the prices are higher.

4.4.1 Winter and summer

Looking the results into more detail the variation within a week can be analyzed. Figure 4.14 and 4.15 shows the average prices for Thursday, Friday and Saturday in week 3 and week 28. Starting with the winter week, it can be seen that the cases BAU, SUN and DIR have a well-known curve: higher prices in the day with highest in the morning and the afternoon and lowest prices during the night. The weekdays has a flatter curve in the weekend. Also an expected difference between these cases is present: the curve for case SUN is lower than BAU, and case DIR is lower than case SUN.

The cases PAS, HPU and OTH have a flatter profile with little difference between day and night. However, there are a larger increase during the day in the weekdays compared with the weekend. The prices are as expected significantly lower than in case BAU, and is due to the reduced demand.

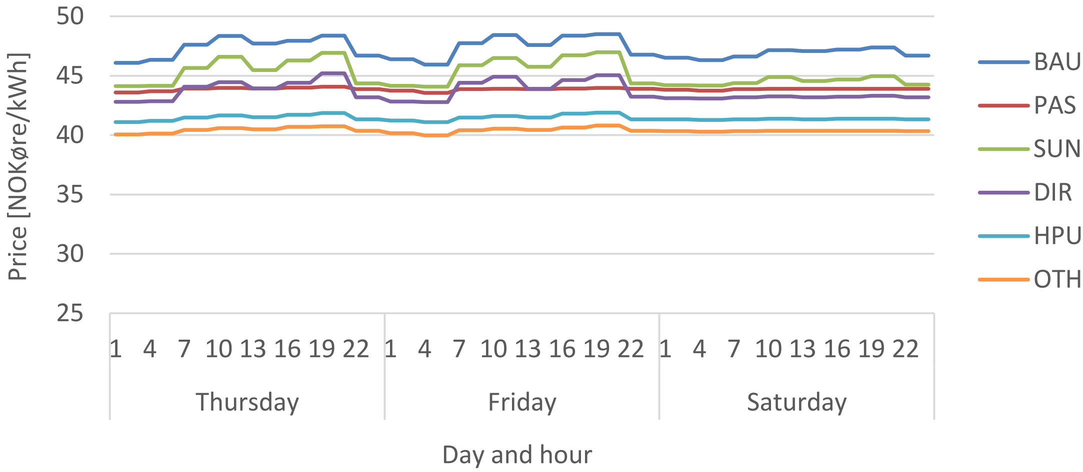

Figure 4.14: *Prices in NO2 in week 3*

In the summer week, there are some very interesting findings: The well-known price curve is turned upside down. The prices are highest in late evening and night and lowest during the day for cases with solar power. In the winter week, there was a difference in prices between case SUN and DIR throughout the whole week, while in the summer week they follow each other closely. Otherwise, the case HPU and OTH have, as expected, the second lowest prices and lowest prices respectively.

For case PAS, there is here a larger difference between night and day, presumably because of the lower heat demand. During the summer, demand is mostly the specific electrical demand.

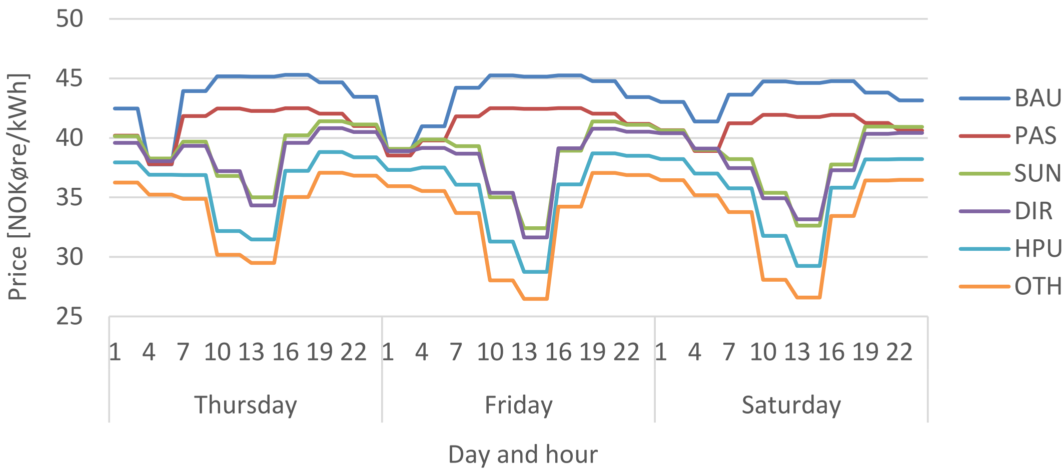

Figure 4.15: *Prices in NO2 in week 28*

4.4.2 Wet, normal and dry years

The differences in weekly prices in a normal, wet and dry year are evident, as Figure 4.16 shows. In the normal year (2006) the difference between case BAU and HPU is familiar, cf. the earlier results shown in Figures 4.10 and 4.13. In the dry year the difference between case BAU and HPU is smaller and the average price increases. Compared with the normal year, the price is escpesially higher in the winter and spring after the inflow usually increases. The price drop due to increased inflow in spring is not present in the dry year.

In the wet year, the situation is very different from the normal and dry year: The system experiences a price collapse in both model cases BAU and HPU. The price in case BAU decreases from 46 NOKøre/kWh in week 1 to 33 NOKøre/kWh in week 19, before it increases again. From week 26 to 28 there is as massive drop in prices from 36 NOKøre/kWh to 11.5 NOKøre/kWh. In case HPU the prices drop even more. The price is just above 40 NOKøre/kWh in the three first weeks of the year and is below for the rest of the year. The prices decreases until week 19 before it increases again the next three weeks before it drops to 0.30 NOKøre/kWh in week 28. Most of the year the price is below 30 NOKøre/kWh, and in 12 of the weeks the price is lower than 20 NOKøre/kWh.

The price collapse shows that in a year with very much inflow, it is difficult to handle all the water. Also, looking back at the spillage in the wet year in Figure 4.8 shows the same. However these are years with a very high inflow and are well above the normal inflow and does ot happen very often. It cannot be expected that the power system should be able to handle this very high inflow.

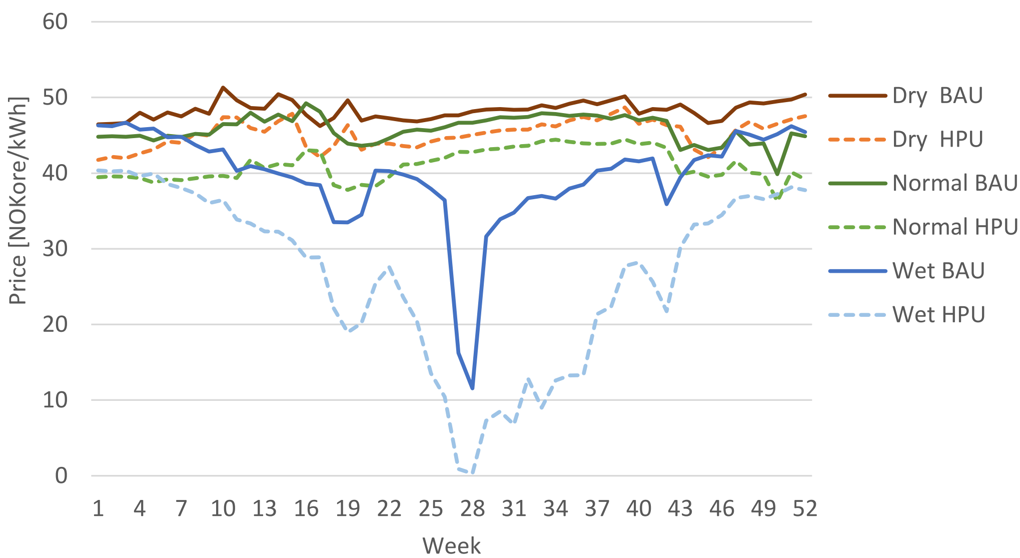

Figure 4.16: *Average weekly prices in NO2 for a normal, wet and dry year.*

4.5 Exchange

The results for exchange show a large effect of lowering demand and introducing solar power. In Figure 4.17 the duration curve for the total exchange for Norway is shown. The duration curve applies for the entire simulation period with every price period, and is given by a share of the simulation period. For every case, there is a shift to the right compared with case BAU giving more export and a higher share of export at maximum capacity. In case BAU the share of maximum export is approximately 6 %. The share increases for each case. In case HPU there is maximum export 33 % of the time. When there is such a high share of maximum export for all the ZEB-cases, it would have been interesting to see the socioeconomic profit and other effects of increasing the export capacity to i.e. Germany and the UK. For case BAU there are export in 64 % of the time, while in case HPU this number increases to 89 % of the time.

The average amount of energy exported for a year, doubles from 23.3 TWh in case BAU to 46.6 TWh in case HPU. This shows the possibilities to export energy to the neighbouring countries. However, the large implementation of ZEBs are only introduced in Norway. It is not unlikely that the neighbouring countries also will have an increase of ZEBs since they also are affected by the EPBD. The effect of an increase of ZEBs in all countries is difficult to predict, and it would be interesting to analyse a model setup where ZEBs are introduced in a larger scale in the neighbouring countries as well.

The difference between the cases in need of import at a high or maximum level is small. This indicates that there are some strained periods with a need of high import capacity that is not greatly reduced by increasing the production from solar power or reducing the demand. In addition the Nordic system has a larger share of intermittent power production in the ZEB cases, showing that there will be periods where these can not cover the needed demand.

In the figure, there are several plateaus in each curve. The ”longest” plateau is at 6395 MW on the import side. This is a period when there is import on every connection, execpt the North Sea Link cable to the UK, which is at full export in this period, giving a total import of 6395 MW. This is expected as the prices in the UK are higher, as presented in chapter 3.1. This also shows some of the challenges in this model setup, because the neighbouring countries has fixed prices, which in reality also would change. In addition, e.g. Germany has an increasing share of renewables, making it difficult to predict the amount of installed capacity in Germany. Also, as mentioned in Chapter 3.1, the prices for CO_2 and selected fuels are diffucult to predict, which will have major impact on the development of the power systems.

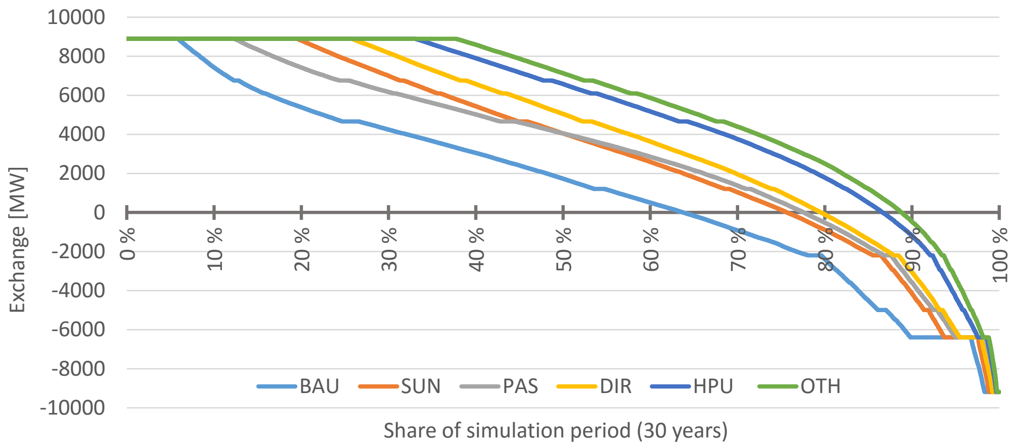

Figure 4.17: *Duration curve for exchange for Norway for all cases in all simulation years.*

In Figures 4.18 and 4.19 the exchange variations through the year can be seen. Results for the other cases are found Appendix F. In case BAU, it can be seen that there is import in winter, spring and in some parts of the autumn, while in the late spring and summer there is export. The export is higher than the import, making Norway an exporting country during a year. The figure shows large variations from week to week, with a difference of more than 2000 MW from one week to another. For case HPU the situation changes and Norway becomes an exporting country throughout the whole year. However, the export during the late spring and summer is larger than during the winter. It can be seen that the average and median values are closer to the maximum values for export during a high share of the summer, showing, as discussed earlier, the need or possibility of increasing the export capacity.

The span between minimum and maximum is different for case BAU and HPU. In case BAU the span is smallest during the winter and highest during the summer. This indicates that there will be a need of import in most years, while the export is more dependent on the inflow during summer. In a year where it has been a lot of precipitation the previous winter, gives most likely more inflow due to snow melting. To avoid spillage, more hydropower is produced and the prices drop and export is more profitable.

Case HPU has an opposite situation of case BAU. The span is smallest during the summer, and highest during the winter. The span during the summer is decreased due to the constraint in capacity in an export situation, and the huge surplus of production during the summer. The span increases in the winter. In some years the need of import is still there, while in others the export is up to 8000 MW. This is also evident in the prices in Figure 4.13 in Chapter 4.4, where the span during the winter increases compared with case BAU. The predictable solar power allows the hydropower producers to produce more to export in years with a high reservoir level. The increased PV-production reduces the effect of huge variations in inflow and precipitation.

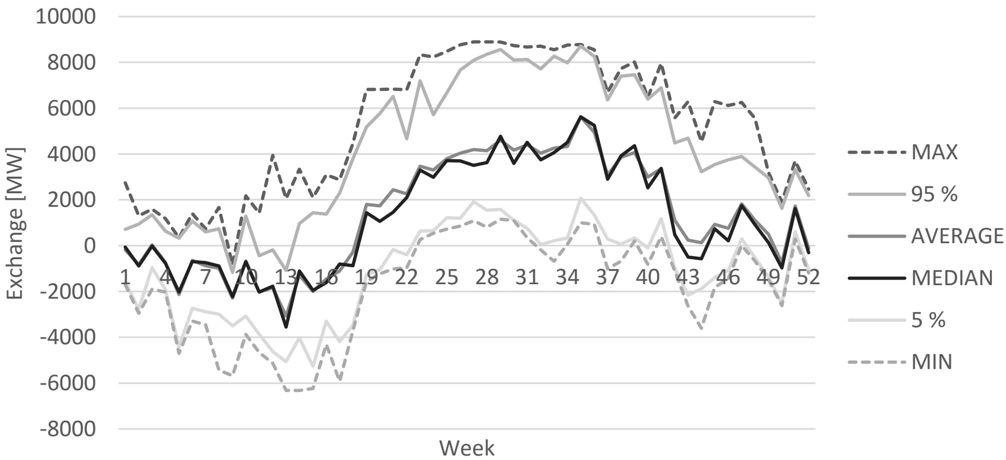

Figure 4.18: *Exchange for Norway during a year. Weekly, average values for case BAU*

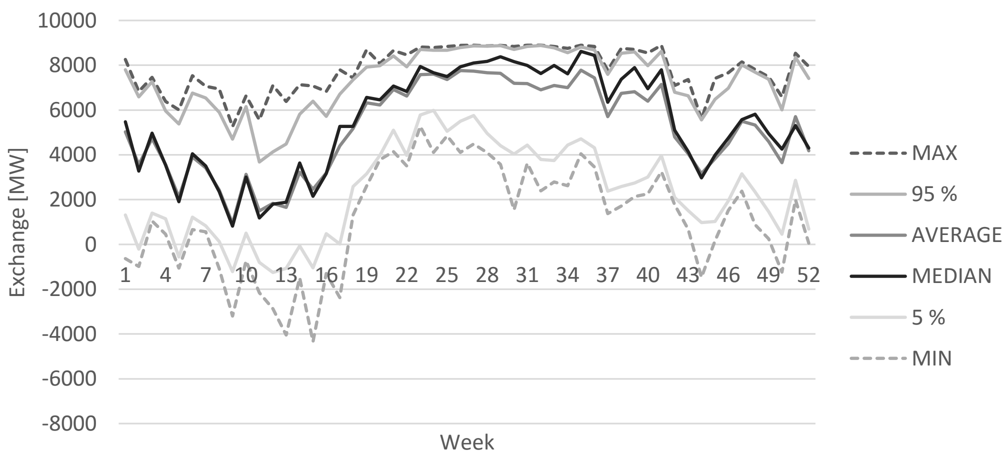

Figure 4.19: *Exchange for Norway during a year. Weekly, average values for case HPU*

4.5.1 Wet, normal and dry years

In Figures 4.20 to 4.22 the results for a normal, wet and dry year (respectively 2006, 1990 and 1996) are shown. The results show that there are large differences in exchange. In all the years and for all cases the export has a larger share of export time, and the export is larger. In the normal year the cases BAU, SUN and PAS have a small share of time where the maximum capacity is met, while the case HPU has a share of approximately 20 %. It can also be seen that the cases PAS and SUN follow each other closely.

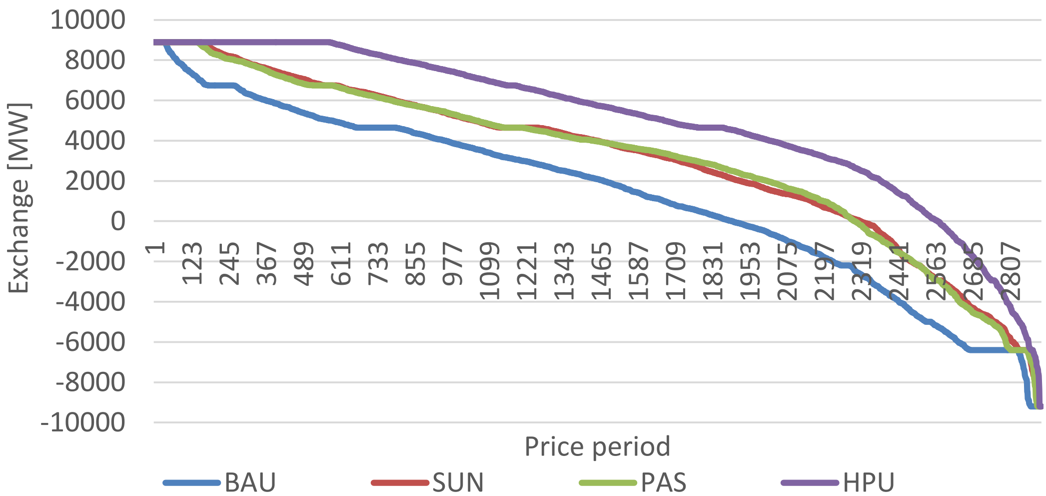

Figure 4.20: *Duration curve for exchange for Norway in total. For selected cases in a normal year (2006).*

In the wet year, the situation is completely different. As seen in Figure 4.8 the spillage in the wet year was much larger than the normal and dry year. For the case BAU circa 31 % of the time is at full export capacity, while the HPU case is at close to the double at 61 %. The HPU case only imports power 5 % of the time in this year. However, also in this year there is import at maximum capacity, and does not change much compared to the normal case. In addition, here the cases SUN and PAS follow each other closely. It also shows that the effect of combining reduced demand and increased PV-production shifts the curve approximately twice as much to the right for large parts of the year.

For the dry year the share of time between import and export is almost the same in case BAU, and the maximum export capacity is not met in any price period during this year. The cases SUN and PAS barely export at maximum capacity. Neither for the case HPU is the share of time with maximum capacity large, with only 4 %.

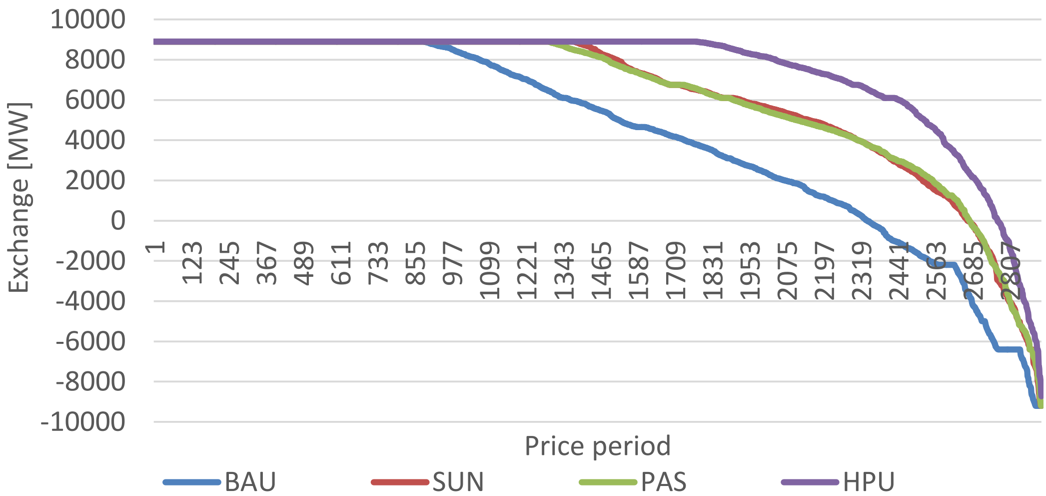

Figure 4.21: *Duration curve for exchange for Norway in total. For selected cases in a wet year (1990).*

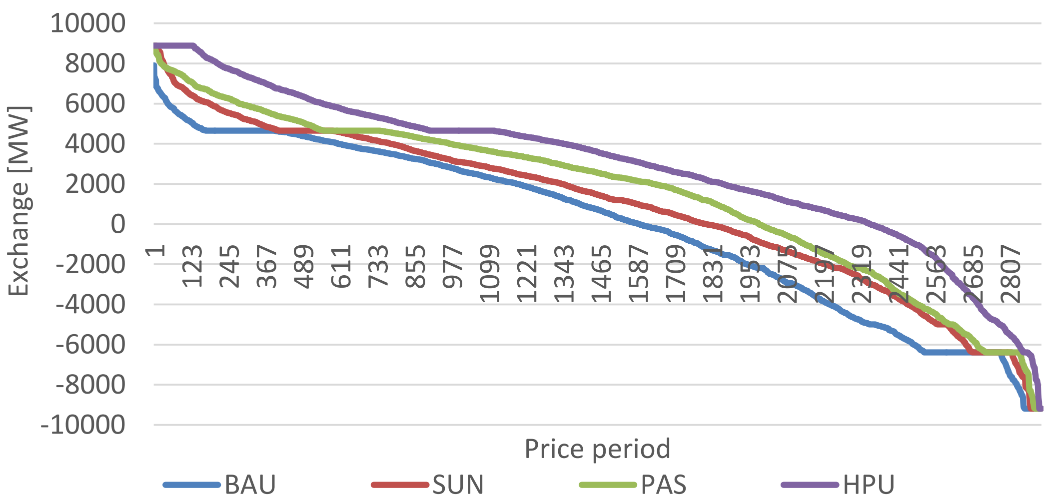

Figure 4.22: *Duration curve for exchange for Norway in total. For selected cases in a dry year (1996).*

5 | Conclusion

A introduction of a large share of ZEBs in Norway has a significant impact on the Norwegian and Nordic power system. The implementation of ZEBs gives a lower demand during the winter and higher power production in the summer. This results in a increased surplus in the power balance in Norway from 10.0 TWh in case BAU to 43.5 TWh in case HPU while it decreases in the other Nordic countries. The production in Finland and Denmark decreases, while the demand increases in Sweden and Finland. Also for the cases SUN and PAS there are a similar trend, but not in the same extend as the ZEB-cases.

The total CO_2 emissions from power production within the Nordic countries is reduced, due to lower prodcution from thermal power plants, mostly coal-fired plants. Compared with case BAU the reduction is 5.32 mill. tonnes. The CO_2 emissions per kWh produced in the Nordic power system reduces from 97.8 gCO_2/kWh in case BAU to 83.9 gCO_2/kWh in case HPU.

The cases with increased PV-production has a significantly different reservoir handling than the cases BAU and PAS. The reservoir level is lower due to the predictable PV-production in the summer and the reduced demand in winter. The difference is highest in the spring and summer. In case PAS with the reduced demand, the reservoir level is lower in autumn and winter, due to lower risk of rationing in winter, allowing increased production in the autumn.

The average prices is reduced, especially in the summer and to a greater extent in the ZEB-cases. Also the classic price reduction during the spring inflow is amplified. In a chosen summer week the classic daily price profile is turned up side down in the cases with PV-production, giving the highest price during late evening and night. In a wet year the system experiences a price collapse, while in a dry year there is sligthly an increase in price compared to a normal year. In the ZEB-cases the price collapse is present in several years.

Due to higher production and lower prices the export increases. In case BAU the share of maximum export is 6 %, while in case HPU this increases to 33 %. Compared with case BAU, where it is import during winter and export during summer, the case HPU does a shift to only exports throughout the whole year. The average and median value of export is approximately 8000 MW during summer, and lies closely to maximum export at 8895 MW.

6 | Further work

- The results shows an increased surplus of power in the Norwegian power system, decrease of power prices and full export in a higher share of the time. It would be interesting to see the effect of increasing the exchange capacity from Norway to the neighbouring countries.
- In this thesis only Norway has introduced a large share of ZEBs in the power system. All the neighbouring countries are affected by the Energy Performance of Buildings Directive (EPBD), and would probably increase their share. Eventhough a share of 50 % ZEBs is unlikely in 2030, it would have been interesting to see the effect of reducing demand and on-site power production.
- As seen in the results, nuclear power is a base load in the Nordic power system. In the model setup nuclear power is reduced in Sweden. If Sweden where to reduce the nuclear power further and increase the share of intermittent production, would the power system be able to deliver enough power at all times?
- In this thesis the PV-production is equal for every year. The possibility of constructing energy series for PV-production for the historical years as for inflow and temperature, should be considered.

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Appendices

A | Model setup and cases

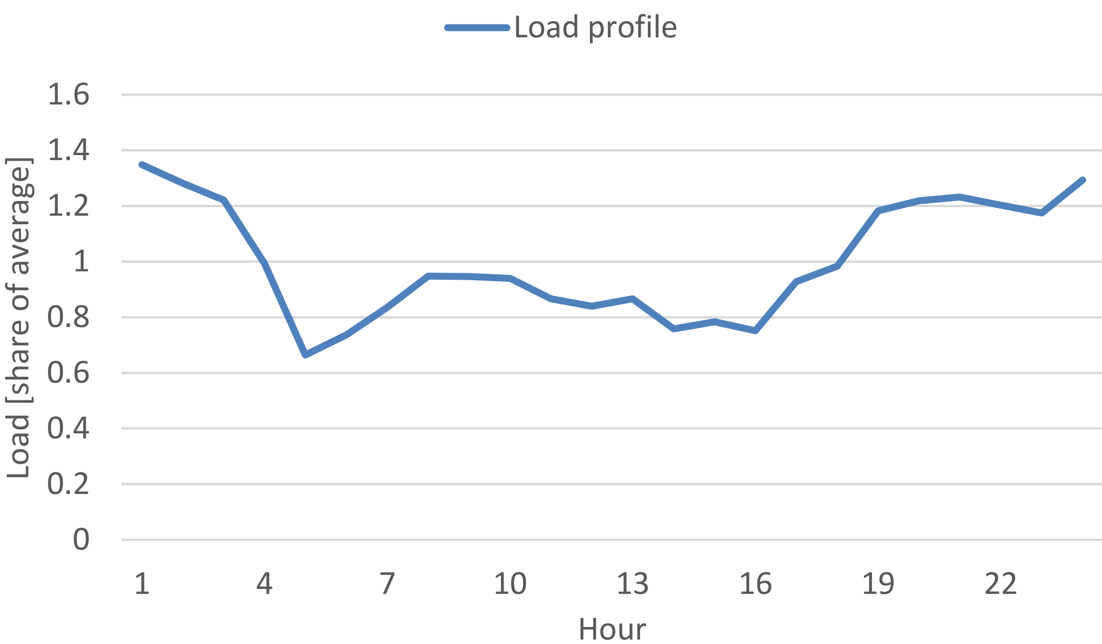

Figure A.1: *Load profile for electric vehicles over one day*

B | Power balance and emissions

Table B.1: *Power balance in Nordic countries for cases DIR and OTH.*

Case DIR	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	169.1	157.7	37.3	103.0	467.2
Demand [TWh]	135.1	145.3	37.2	96.1	413.8
Balance	33.8	12.5	0.1	6.9	53.3
Case OTH	**NOR**	**SWE**	**DK**	**FIN**	**Nordic**
Production [TWh]	168.5	157.9	36.8	101.1	464.3
Demand [TWh]	121.2	146.9	37.2	97.1	402.4
Balance	47.4	11.0	-0.5	3.9	61.8

Table B.2: *CO_2 emissions from electric generation [gCO_2/kWh] for selected products. [30]*

Product	**gCO2/kWh**
Natural gas	400
Heavy Fuel Oil (HFO)	675
Coal (Bituminous coal)	875
Lignite	1035
Peat	750

C | Reservoirs

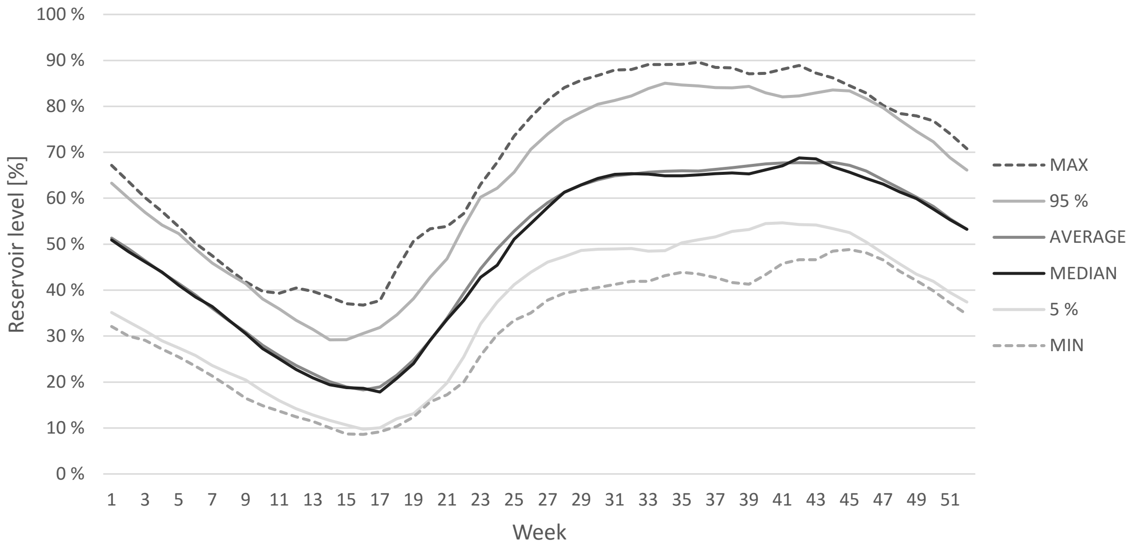

Figure C.1: *Reservoir level for case SUN for Norway. Includes percentiles: 5% and 95%*

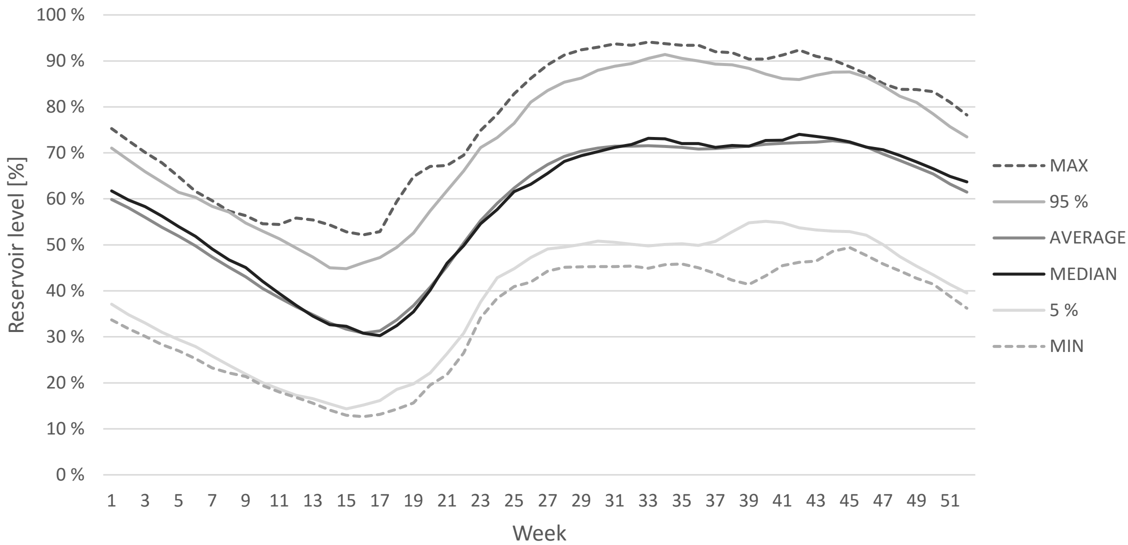

Figure C.2: *Reservoir level for case PAS for Norway. Includes percentiles: 5% and 95%*

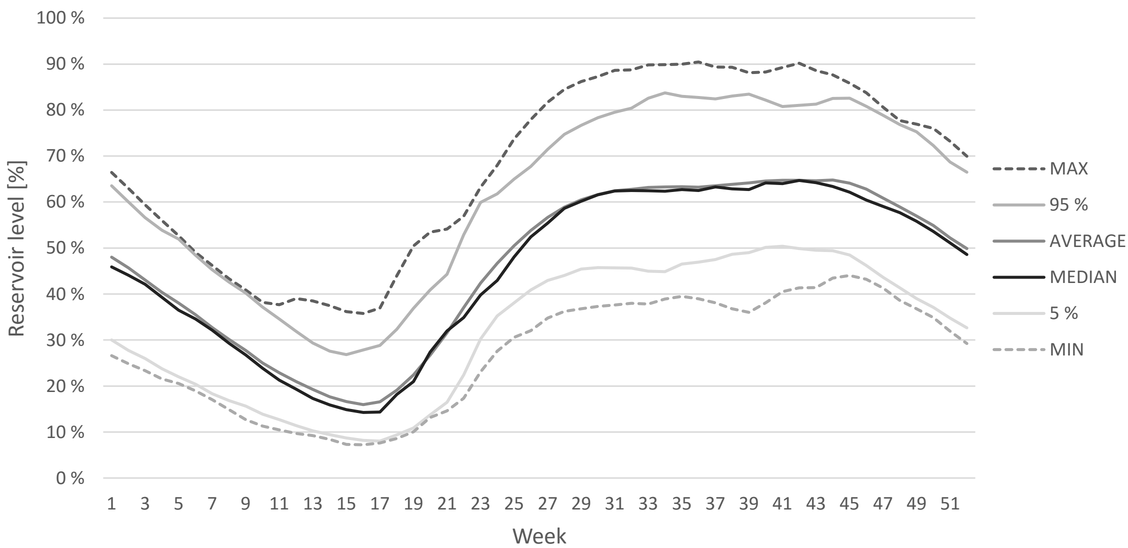

Figure C.3: *Reservoir level for case DIR for Norway. Includes percentiles: 5% and 95%*

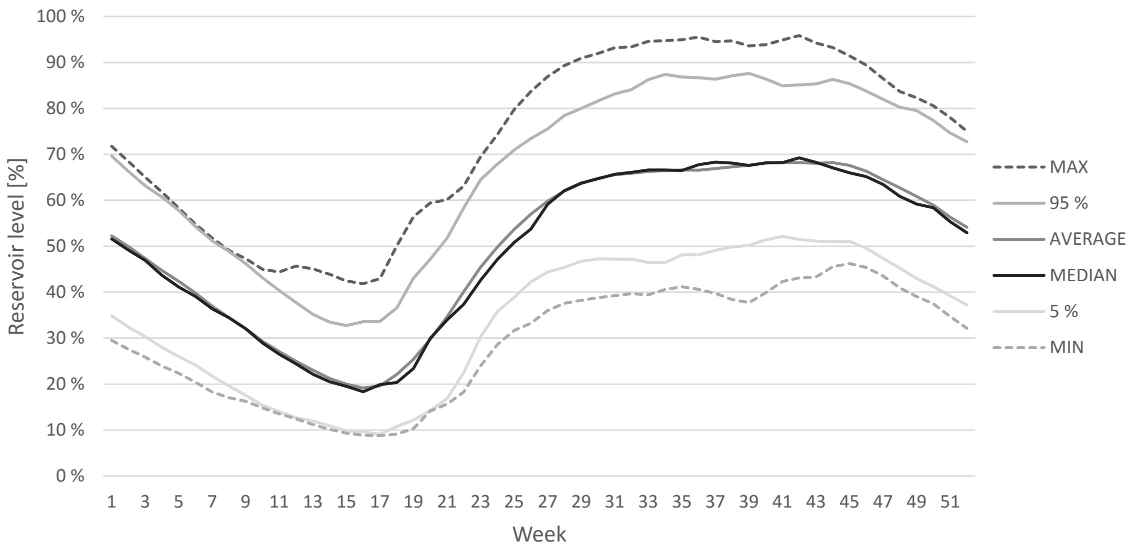

Figure C.4: *Reservoir level for case OTH for Norway. Includes percentiles: 5% and 95%*

D | Spillage

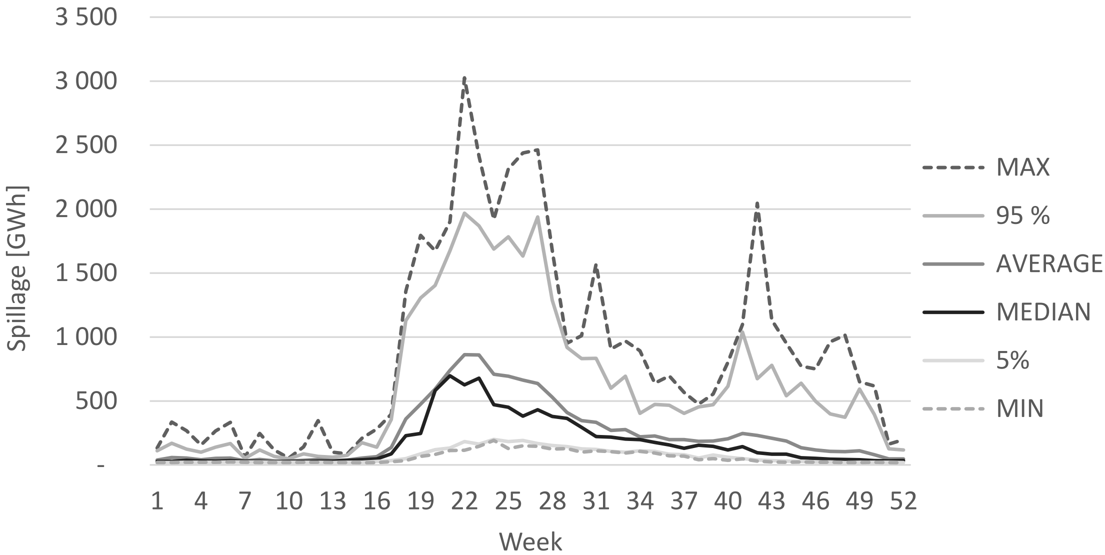

Figure D.1: *Spillage for case SUN for Norway. Includes percentiles: 5% and 95%*

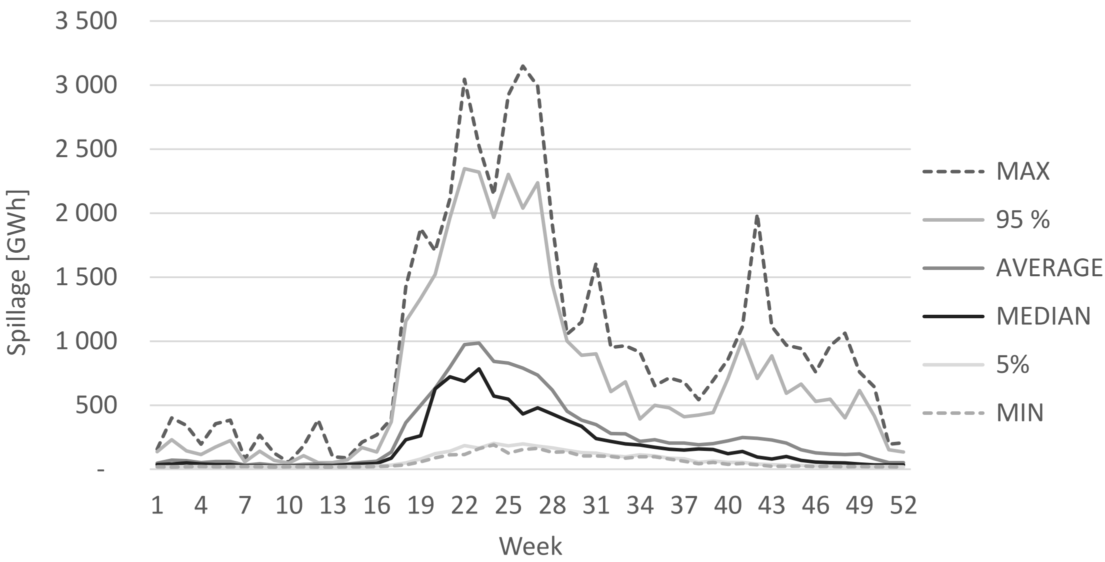

Figure D.2: *Spillage for case PAS for Norway. Includes percentiles: 5% and 95%*

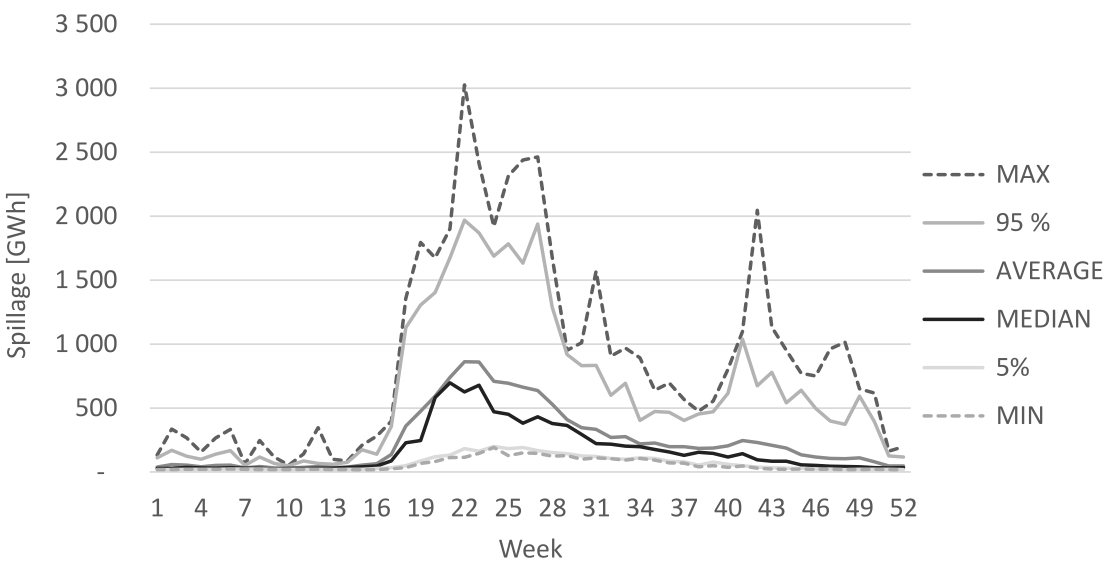

Figure D.3: *Spillage for case DIR for Norway. Includes percentiles: 5% and 95%*

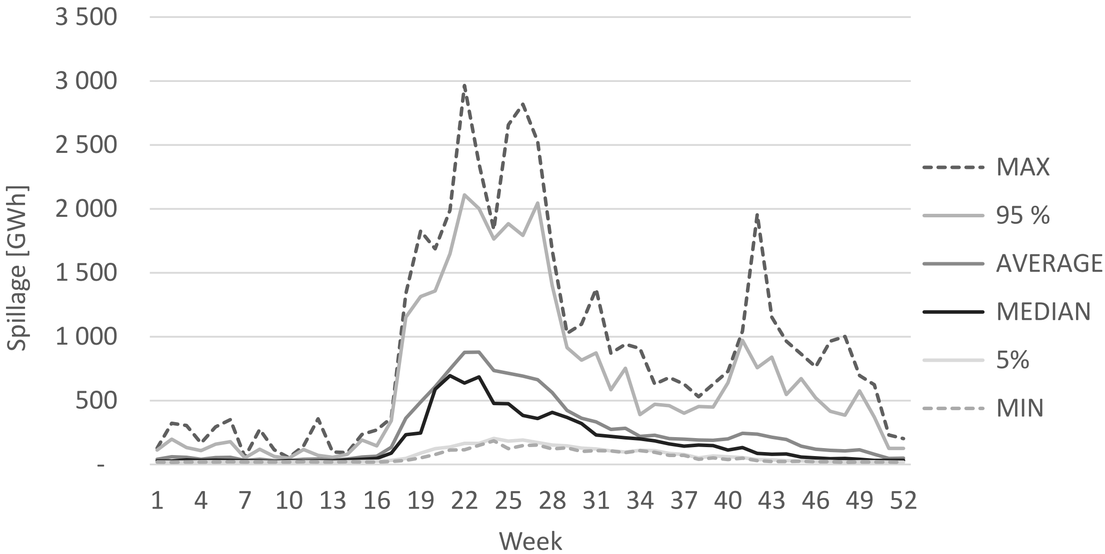

Figure D.4: *Spillage for case HPU for Norway. Includes percentiles: 5% and 95%*

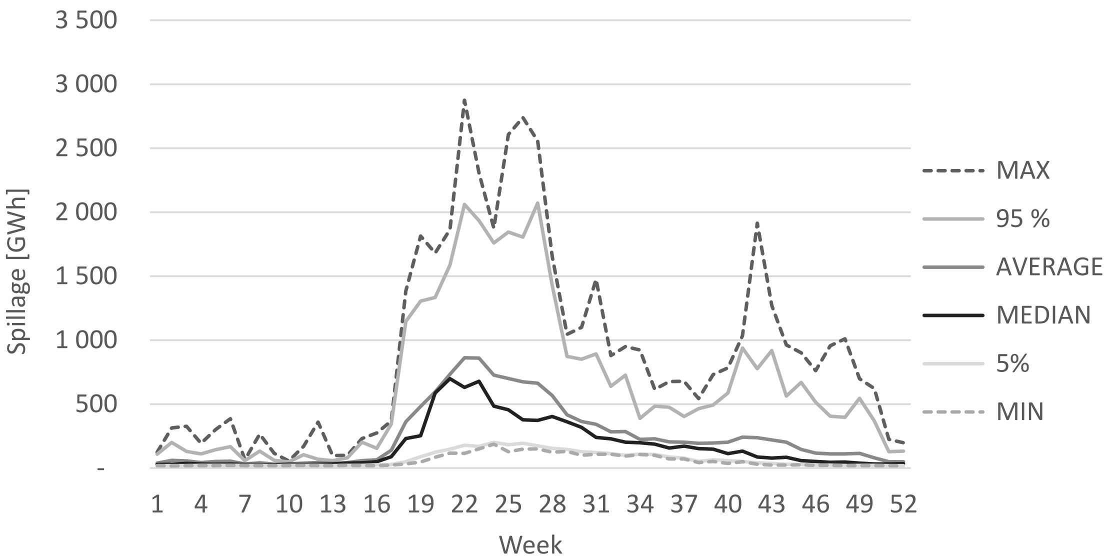

Figure D.5: *Spillage for case OTH for Norway. Includes percentiles: 5% and 95%*

E | Prices

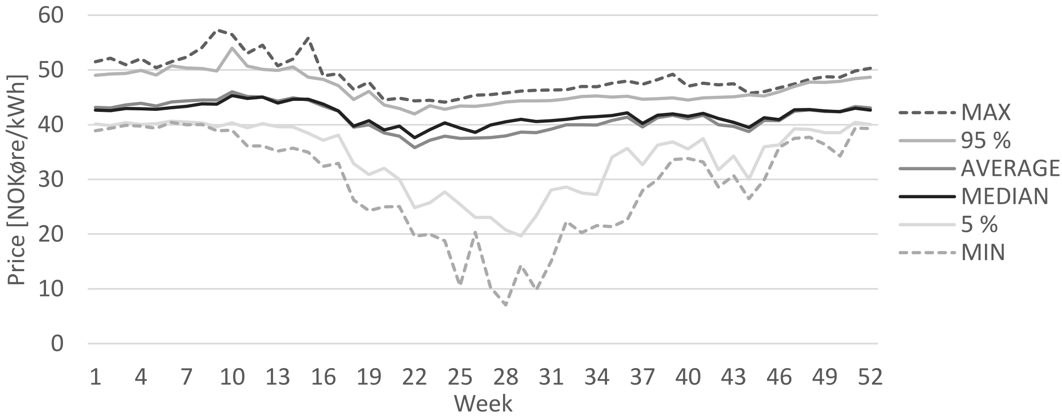

Figure E.1: *Prices in price area NO2 for case DIR*

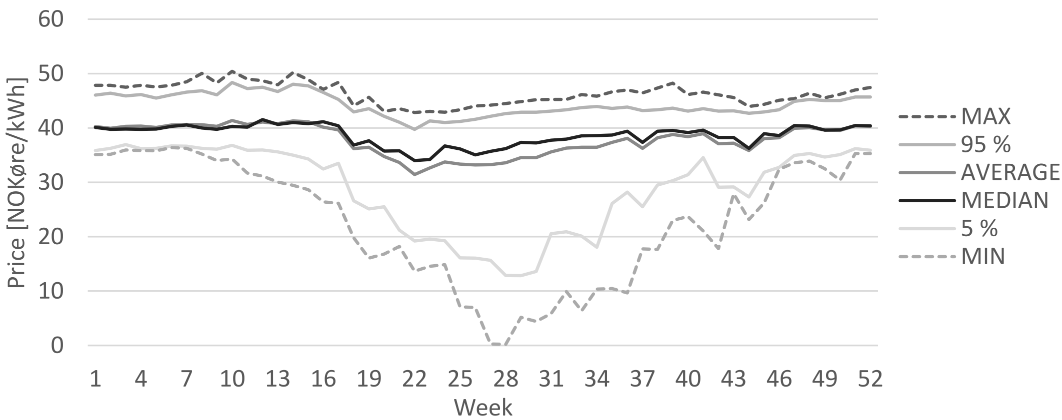

Figure E.2: *Prices in price area NO2 for case OTH*

F | Exchange

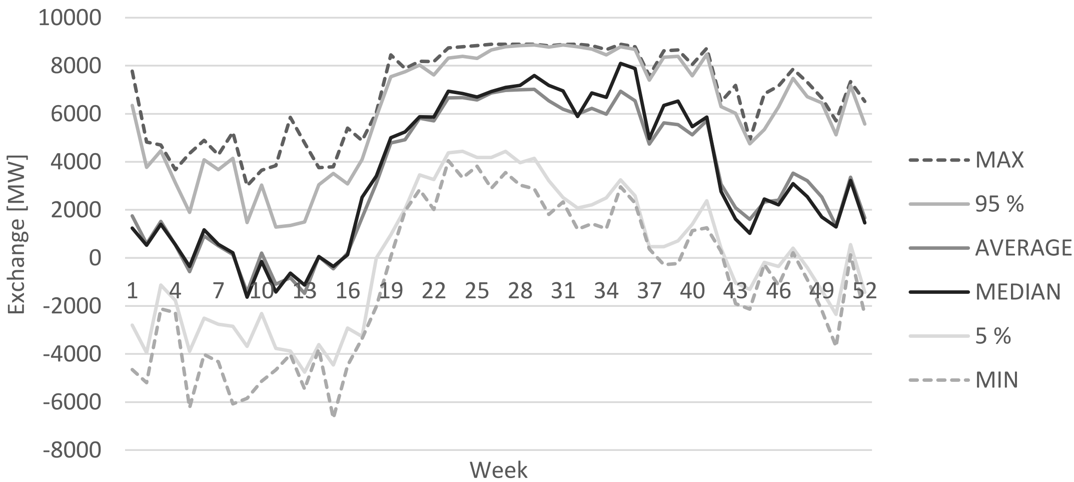

Figure F.1: *Exchange from Norway during a year. Weekly, average values for case SUN*

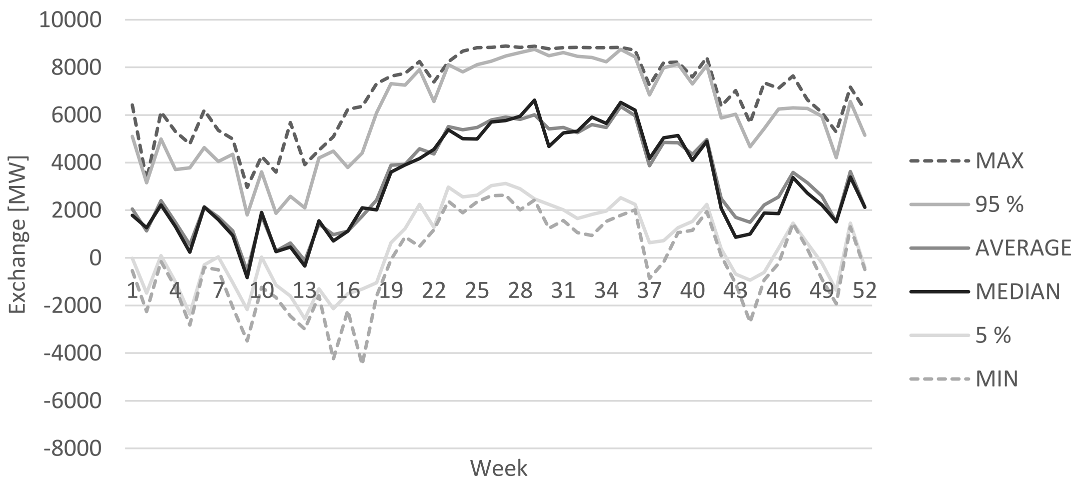

Figure F.2: *Exchange from Norway during a year. Weekly, average values for case PAS*

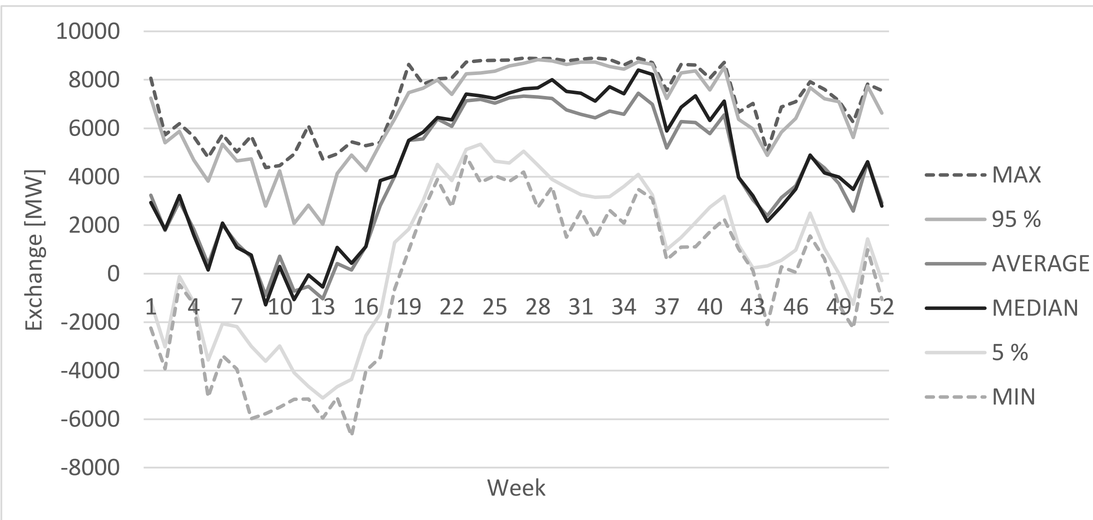

Figure F.3: *Exchange from Norway during a year. Weekly, average values for case DIR*

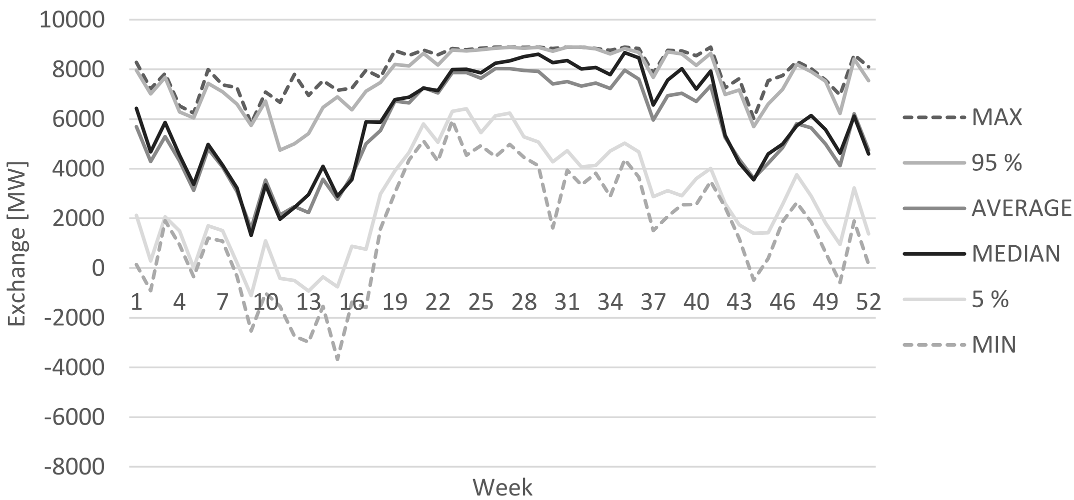

Figure F.4: *Exchange from Norway during a year. Weekly, average values for case OTH*