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Modelling of future demand profiles and response

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Master of Energy and Environmental Engineering
Submission date: June 2017
Supervisor: Gerard Doorman, IEL
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This report is the final deliverance of a master thesis which concludes a Master of Science in Energy and Environment at NTNU. It was written during the spring of 2017, at the Department of Electric Power Engineering at the Norwegian University of Science and Technology, NTNU. This thesis was developed and written in collaboration with Statnett SF.

I would like to extend appreciations to my supervisor Gerard Doorman, for good advice and guidance through this process. Thanks to Lasse and Karam for providing valuable insights to the Leopard model, and to Vegard and Jørgen for interesting discussions regarding the topic in the beginning of the semester.

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Abstract

The installation of smart metering systems to all electricity consumers in Norway, commissioned by NVE, is predicted to enable more active power consumers, due to a two-way communication of price and consumption information. A behavioral change in consumption is therefore expected, through the facilitation of *Demand Response (DR)*.

The EFI's Multi-area Power-market Simulator (the EMPS model), is an important tool in Statnett's long-term market analysis, know for its ability to model and handle hydropower production. This thesis aims to evaluate ways to model DR within general consumption in the EMPS model. As the most straightforward way proved to be a change in the input demand profiles, new profiles were created for 2030. These were collected from another model, the Leopard model, a tool developed for Statnett to project future consumption and its annual distribution. Here, the demand profiles for residential consumption are optimized to even out daily consumption, thus imitating DR. The primary sector and the service sector were provided with non-flexible demand profiles.

Five cases have been developed and evaluated to test the new profiles, differing in their way of modelling firm demand. Three cases were provided with the new profiles, in addition to the new, projected consumption volumes applied in all cases. In the analysis, the three Leopard cases were compared to the original, non-flexible modeling of the 2030 power system, based on their change in consumption, prices, cross-border power exchange, socioeconomic benefits and profitability to the consumer. Even though all cases showed overall reductions in peak hour consumption and average prices, only one case yielded positive economical results to the consumer and to society. In this case, a finer resolution of general consumption was introduced, in addition to the extraction of non-temperature dependent flexible household demand, namely heating of water and charging of electrical vehicles. This way of modeling, combined with the change in temperature dependency proved to be the most beneficial in regards to demand response.

Even though positive results were seen in one of the cases, more thorough

ways of modelling demand response should be evaluated, with a price based optimization. Additionally, all segments within consumption should be evaluated, as the potential for DR is not exclusively isolated in the residential sector. However, with a more active power consumer, a need for more frequent updates of the demand profiles might evolve. Therefore, Statnett should consider the implementation of demand profiles projected in the Leopard model, in addition to the projected annual consumption quantities.

Sammendrag

Installasjonen av smarte målesystemer til alle elforbrukerne i Norge, på vegne av NVE, forventes å muliggjøre mer aktive strømforbrukere som et resultat av toveiskommunikasjon av pris- og forbruksinformasjon. En atferdsendring i forbruket er derfor forventet, gjennom tilrettelegging av *Forbrukerfleksibilitet (FF)*.

EFIs Multi-Area Power Market Simulator (EMPS-modellen), er et viktig verktøy i Statnetts langsiktige markedsanalyse, kjent for sin evne til å modellere og håndtere vannkraftproduksjon. Denne oppgaven tar sikte på å evaluere måter å modellere DR innenfor det alminnelig forbruk i EMPS-modellen. Da den enkleste måten viste seg å være en endring i forbruksprofilene, ble det opprettet nye profiler for 2030. Disse ble hentet fra en annen modell, Leopard-modellen, et verktøy utviklet for Statnett for å framskrive forbruk og dets fordeling gjennom året. Her er forbruksprofilene for husholdninger optimalisert for å jevne ut det daglige forbruket, og dermed etterligne forbrukerfleksiblitet. Primærenæringen og tjenestesektoren ble tildelt ikke-fleksible forbruksprofiler.

Fem caser er utviklet og evaluert for å teste de nye profilene, der forskjellen ligger i deres måte å modellere fast etterspørsel. Tre caser ble tildelt nye profiler fra Leopard modellen, i tillegg til de nye fremskrevne forbruksmengdene som ble anvendt i alle tilfeller. I analysen ble de tre Leopard-casene sammenlignet med den originale, ikke-fleksible modelleringen av 2030-kraftsystemet, basert på deres endring i forbruk, priser, kraftutveksling til utlandet, samfunnsøkonomiske fordeler og lønnsomhet for forbrukeren. Selv om alle tilfeller viste reduksjoner i hly-last forbruk og gjennomsnittspriser, ga bare ett av tilfelle positive økonomiske resultater for forbrukeren og samfunnet. I dette tilfellet ble det innført en finere oppløsning av alminnelig forbruk, i tillegg til at ikke-temperaturavhengig fleksibel husholdningsforbuk ble trukket ut, nærmere bestemt oppvarming av vann og ladning av elektriske kjøretøy. Denne måten å modellere fastkraft på, kombinert med endringen i temperaturavhengighet, viste seg å være den mest fordelaktige med hensyn på forbrukerfleksibilitet.

Selv om ett av casene viste positive resultater, bør en mer grundig måte å modellere forbrukerfleksibilitet evalueres, med fokus på prisbasert

optimalisering. I tillegg bør alle kategorier innen forbruk vurderes, da potensialet for FF ikke utelukkende er isolert i husholdningen. Likevel, mer aktiv strømforbrukere kan føre med seg et behov for hyppigere oppdateringer av forbruksprofilene i modellen. Derfor bør Statnett vurdere en implementering av forbruksprofilene fremskrevet i Leopard-modellen, i tillegg til de anslåtte årlige forbruksmengdene.

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Abbreviations

DSR	Demand side response
DR	Demand Response
EMPS	EFI's Multi-area Power-market Simulator
TSO	Transmisison System Operator
SSB	Statistics Norway
EV	Electrical Vehicles
PII	Power Intensive Industry
ZEB	Zero Emission buildings
PV	Photovoltaic
PS	Primary sector
DP	Distributed generation
VAT	Value added tax

1 Introduction

Background and motivation

Following the full scale rollout of smart metering devices commissioned by NVE, an activation of the average power consumer is expected. As the grid becomes smarter, with a larger share of intermittent, renewable production, the possibilities and need for more flexible consumers arise. Pilots investigating different ways of activating the consumer in Hvaler and Steinkjer, show that a combination of education of the consumers and economical incentives can contribute to make the average Norwegian household customer a participating component in the power system (15). The European Network of Transmission System Operators for Electricity (ENTSO-E) states in its demand side response policy paper from 2014 (7):

> *"Demand side response (DSR) is a key component in the successful evolution of the power system from a conventional based generation system to one that has significant contributions from intermittent sources of generations and power intensive loads. To achieve the EU's 2030 and 2050 energy policy and decarbonisation targets, DR uptake must therefore be broad and deep."* (7)

Problem definition

To conduct long-term market analysis, Statnett develops and maintains a number of different models for the future power system. It is important that these models are continuously updated to best reflect the expected future power system. Due to an increased activation of the consumer through a smarter grid, the demand side is expected to experience a great change in behavioral consumption patterns. Thus the need for improved modeling of consumption, to implement prospective consumer flexibility and demand response.

The goal of this master thesis is to test new demand profiles, where demand response has been implemented. This is done to evaluate methods for implementation of flexibility in the EMPS model. The demand profiles are based on a new demand projection model developed for Statnett, called the Leopard model. These are then compared to historical profiles, based on a set of different evaluation criteria. Furthermore, the results are compared to the work conducted in a previous master thesis, written by Tore Dyrendahl (4).

The objectives are as follows:

1. Create new demand profiles in accordance with the Leopard model.
2. Implement demand response in the new demand profiles.
3. Simulate the new consumption profiles in a base case for 2030, developed by Statnett.
4. Preform analyses to evaluate the impact of demand response implementation.

Project scope

The consumption profiles studied in this thesis focuses on changes in general consumption in Norway. Research has shown that the consumers with the greatest non-customized DR potential are found in the residential sector, as the behavior of household consumers are fairly similar (15). Therefore, the scope is further narrowed down to study the residential sector, where a large scale implementation of DR is expected following the installation of smart metering systems in households. However, to ensure the transition from non-flexible consumption to full utilization of DR, 2030 has been chosen for the analysis.

Five cases have been developed, based on the structure of the Leopard model. These changes the way of modeling firm demand in the EMPS model, by breaking down the original categorization of general demand. The two first cases are provided with the original demand profiles implemented by Statnett, while the three remaining cases test the new profiles produced by the Leopard model.

Relation to specialization project

A preliminary work for this master thesis was conducted during the fall of 2016, *Demand response in the EMPS model* (15). The objective of this thesis was to evaluate the position of demand response in Norway today, in addition to become acquainted with the EMPS model. This project form large parts of the theoretical basis utilized in this thesis. In parts where material from the specialization project has been used, a statement will be provided.

Report structure

Following this introduction, the thesis is divided into three parts. Firstly, the necessary theoretical background is provided. Secondly, the methods used to evaluate the new profiles are disclosed. Lastly, the results and discussion are presented, followed by a conclusion and recommendations for further work.

Part I: Theoretical background
The first two chapters of this part are heavily based on the preliminary study for this thesis. Chapter 2 gives an overview of the Norwegian and Nordic power system, and the possibilities of demand response. Furthermore, in Chapter 3 the most relevant parts of the EMPS model are elaborated. In Chapter 4, the structure and the possibilities concerning the Leopard model is presented.

Part II: Method
Chapter 5 firstly present the 2030 base case utilized in the simulations. In the second part, it describes the five different cases developed and simulated in this thesis. In Chapter 6 the evaluation criteria are presented, followed by a disclosure of the limitations and sources of errors in the analysis.

Part III: Analysis
In Chapter 7, an analysis comparing the five different cases is preformed, presenting and discussing the results gathered from the simulations. Additionally, the results are compared to another master thesis. Lastly, a conclusion and suggestions to further work is presented in chapter 8.

2 Background

This chapter provides a short introduction to the Nordic power system, including a closer look into the Norwegian demand. Furthermore, a closer description of smart grid and demand response is given.

Large parts of this chapter are directly cited from the project report of the preliminary study conducted prior to this thesis.

2.1 The Norwegian and Nordic power system

The Norwegian power system is closely connected to the rest of the Nordic through Nord Pool, the common Nordic power exchange. It manages the physical and financial trade through operation of three markets: the day-ahead market, the intraday market and the financial market. In addition to Norway, Sweden, Denmark and Finland, the Baltic countries participate in the trade (16). Figure 2.1 displays how Nordic consumption is distributed between the different countries, as well as the total power generation distribution by source. In the Nordic region, hydro power is dominant, heavily distributed in Norway.

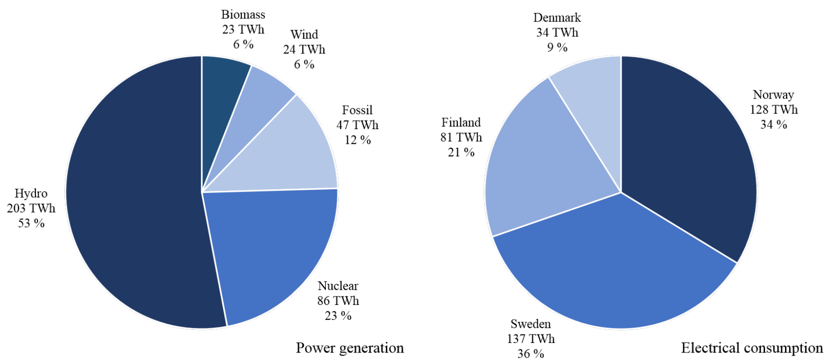

Figure 2.1: The Nordic energy mix, power generation by source to the left and electrical consumption by country to the right (22).

A constant equilibrium between demand and supply is necessary to maintain the security of supply. In the day-ahead market Nord Pool receives hourly bids from buyers (typically a utility) and sellers (mostly power producers) containing volumes of power and the price of this volume. The price is set through a market clearing process, simply put: the intersection where the accumulated supply price curve meets the accumulated demand curve, illustrated in figure 2.2. Market clearing is done and published around noon one day prior to operation. The accumulation of bids ensures the usage of the cheapest production units, and in the hydro dominated Nordic market this results in relatively low power prices.

As about 95 % of the Norwegian distributed power generation is derived from hydro power, the power system is sensitive to variations in precipitation and inflow. Production capacity can differ with as much as 50 TWh between very dry and wet years(26). At the same time, the natural filling of the reservoir follows a recurring pattern each year, with filling and depletion seasons in the summer and the winter time respectively. This pattern is disproportional to the Norwegian consumption pattern, further explained in the next subsection, which results in a higher likelihood of strained power situations during the winter in dry years. Additionally, when the demand exceeds production and transmission capacity, the grid experiences bottlenecks which increases the power price.

In extreme situations, like in dry years with high consumption and high power price, one runs the risk of *rationing*. This means that one either has to reduce the price of independent general consumption or have power intensive industries disconnects due to high power prices. This kind of situation inflicts big socioeconomic costs and consequences, and should be avoided (11)(10).

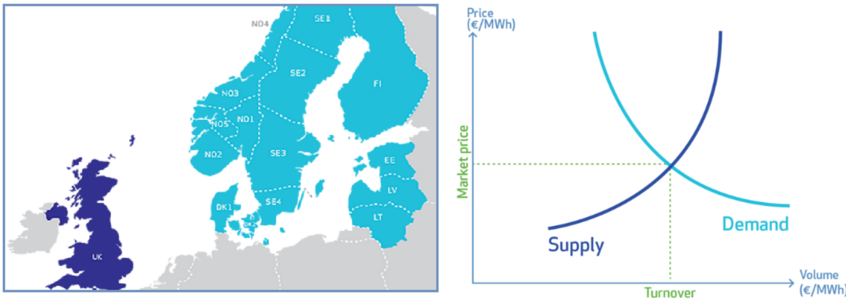

Figure 2.2: Bidding areas and market clearing process used by Nord Pool (16)

Figure 2.2 also show the different bidding areas established by the local Transmission System Operators (TSO) for their respective countries. Norway has five such areas. These account for the physical transmission constraints within the power system, and they ensure that regional market conditions are reflected in the price (16). If large power volumes need to be transmitted to meet demand through constricted connections, bottlenecks can occur, resulting in different area prices. The day-ahead market calculates both these power prices, as well as the system price, where all transmission capacity is disregarded.

The end user market is organized through various types of contracts. The three general categories are *spot price contracts*, *fixed price contracts* and *variable price contracts*. The first one follows variations in the spot price set by Nord Pool, with an added premium from the power supplier. Firm contracts has a set price over a longer period of time, for example a year, based on expected system prices. Customers who do not choose one of the former options are given variable price contracts, where prices can change on a few weeks notice, as they vary according to the power market (**?**).

Norwegian demand

Today, the demand side of the power system is mostly handled by the utilities and network operators, allowing the customer to remain passive. The distributors ensure that power is delivered to the end customer, through trading consumption in the power market (16). To gain an understanding of the behavior of demand, particularly Norwegian demand, this section explains how consumption is classified, its dependencies and how prices reach the customers through the connection of the spot market and the end user market.

Categorization of consumption

Electrical power has a wide range of applications, making the consumption patterns of the different areas of use inconsistent. Accordingly, it is beneficial to separate total consumption into consumption categories when preforming analysis. The data within these categories share similar drivers and parameters, representing parted building blocks within the total power demand(21).

The desired categorization of demand is often limited by the statistics available. As yet, the practice of isolating measuring points for distinct categories has been non-consistent, and regional differences are prominent. This problem induce the need for a wider segmentation of demand in theoretical analysis, where less specific data can be utilized. Based on the demand segments of Statistic Norway (SSB), Optimeering has arrived at a division of the Norwegian power demand as shown in figure 2.3. Here the lowest branch in the tree represent the different consumption categories, while the rows above are the consumption segments based on SSB's classification; primary, residential and service sector and industry and supply (21). The attached power consumption is based on numbers from 2013.

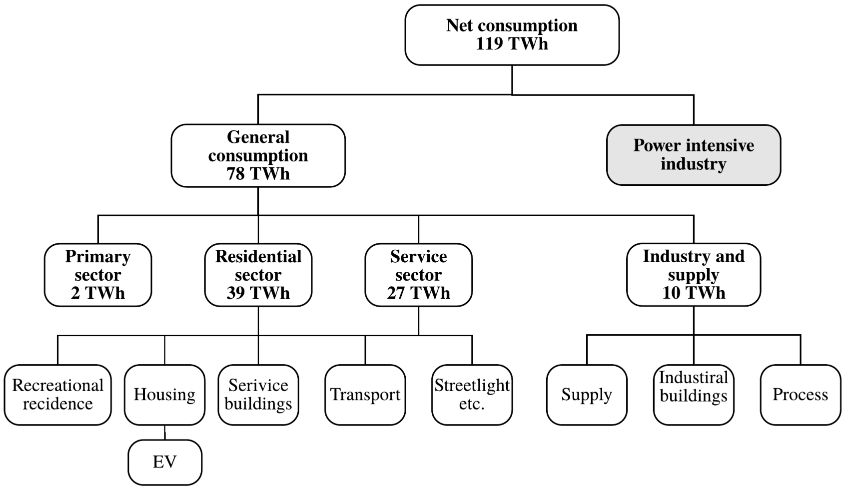

Figure 2.3: The breakdown of Norwegian consumption, with attached values from 2013 (21)

This partitioning is done based on the demand situation in 2013, and it is important to note that the composition may change in the future.

Demand profiles

A demand profile is a curve describing the distribution of consumption within a period of time. The resolution and duration of the curve can differ, depending on what it aims to describe. A weekly profile with an hourly time resolution can depict the fluctuations through a week, revealing low-load periods and peak hours. Meanwhile, a yearly profile with rougher resolution will map out the seasonal variations in demand (21).

Drivers in the Norwegian demand

The power consumption varies with both seasons, the time of week and the time of day. The yearly variations are induced by the Norwegian weather conditions, since the need of light and heating are seasonal dependent. Still, high consumption hours for the households remain the same throughout the year, having a morning peak in hour 9 and generally high consumption in the afternoon and evening for all days of the week. The industry also contributes to peak periods in the morning and afternoon, but less so during the evening. Meanwhile, the production slows down in the weekend, giving the consumption a flatter profile (12).

General consumption is closely correlated to temperature in the short term, as the biggest contribution comes form space and water heating. In the residential sector, the share is as high as 80 % (26). This leads to high consumption during the winter, which corresponds to the depletion season for hydro power, making the prices extra sensitive to the reservoir levels.

Demand elasticity and price sensitivity of Norwegian demand

The exposure to electricity prices is a crucial factor for how quick customer behavior in the end user market is reflected in the spot market and vice versa. Through empirical analyses it has been shown that price changes has an effect on the Norwegian demand, both in the short term in the spot market and in the long term in the end user market. It takes about two to three months before the changes in the spot market is reflected in all end user contracts, concluding that in the medium term these two markets are relatively well connected. However, in the short term they are almost completely separate (12), leading to a limitation of demand elasticity as the price signals in the spot market are not reflected in the end user market. Still, in the third quarter of 2016, the majority of all sectors within general consumption were operating with spot price contracts (17), facilitating a quicker time of response if the price signals are transferred to the consumer.

A way of doing this is through smart metering systems, which will be further discussed in the next section.

2.2 Smart grid and demand response

The Norwegian regulator, NVE (The Norwegian Water Resource and Energy Directorate), has decided that all Norwegian electricity consumers should be provided with Advanced Metering Systems (AMS) by January 1st, 2019, commissioning for a two-way communication between DSO and consuming customers (18).

These meters can measure and report near real-time values of electricity consumption, automatically reporting the data with an hourly or 15-minutes time step to the utility, giving them a better basis for correct billing. When combined with the proper information systems and interface the utility can in return communicate time-of-use information about price and consumption to the customer (18). With visualization solutions through smart phones or in-house-displays NVE reports an 11% reduction potential for electricity consumption in Norwegian households (19).

Following the roll-out of these meters, one of the areas which is assumed to provide new and possibly profitable opportunities in the power system is *Demand Response*(DR). Sintef Energy defines DR in their projects as (10):

The customers ability to alter their consumption or change energy carrier during limited periods, as a response to changes in electricity prices (both grid tariff and market power price)

If facilitated properly, demand response can serve as a mean to ensure market clearing in hours of shortage or power surplus (13). With an increasing share of intermittent power production in the power system, this is a desirable attribute. For the grid operators, DR can serve as a cost-effective alternative to increasing grid capacity to accommodate the straining demand which occur in limited peak hours through the year (15).

2.2.1 Realization of DR potential

In a report provided by Sintef from 2013, the provisional theoretical potential for DR in Norway is estimated at about 1700 MW for general consumption and 3000 MW for power intensive industry (9). To realize this potential, several mechanisms can be utilized. These are illustrated in figure 2.4, and further explained below.

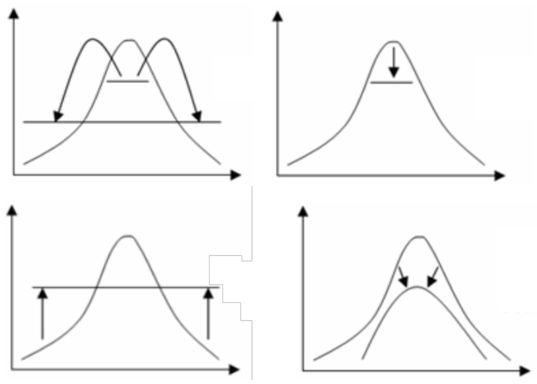

Figure 2.4: 1. Load shifting, 2. Peak clipping, 3.Valley filling, 4.Strategic conservation (9)

1. *Load shifting* - moving the consumption from high-load to low-load periods, for example by charging your electrical vehicle at night instead of when you come home from work.
2. *Peak clipping* - reduction of load in some periods, without increasing load later. For example turning down the temperature on an electrical radiator.
3. *Valley filling* - using electricity as a substitution of other energy carriers, such as oil, in low-load periods. Environmental aspect
4. *Strategic conservation* - Reducing consumption over time, either by a more efficient use of energy, for example through technological advancement, or through initiatives to save electricity.

Degrees of flexibility

Naturally, not all electrical consumption can be utilized in demand response. There are loads which can be switched off for several hours, without causing noteworthy discomfort for the consumer. These loads are usually referred to as *low-priority* demand. Meanwhile, on the other end of the scale *high-priority* demand is rigid and cannot be modified or controlled. The different degrees of flexibility for general consumption are are illustrated in figure 2.5.

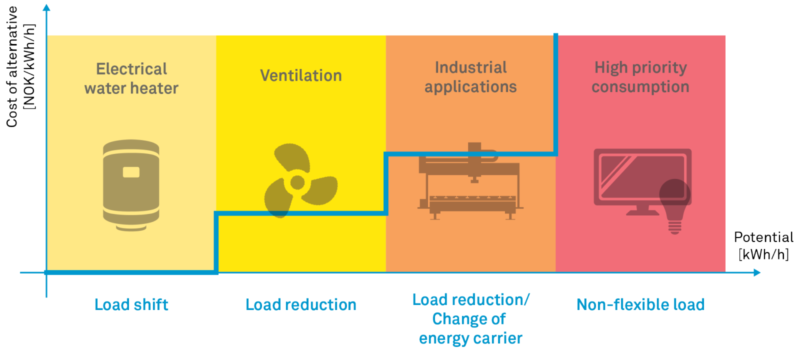

Figure 2.5: Degrees of flexibility in demand (9)

Flexibility in thermal loads of households

The Norwegian residential customers are accustomed to a certain level of comfort. Combined with high willingness to pay and low Norwegian power prices, this limits their willingness to reduce consumption when necessary. Therefore, demand response should be utilized on low-priority loads. As seen in figure 2.5, thermal loads such as electrical water heaters are a good alternative for load shifting. These heaters can be disconnected for 2-4 hours without causing any reduction in comfort (9).

As the Norwegian electricity grid is designed to handle electrical heating, there is a large potential found in strategic conservation through renovation of buildings. However, a reduction of the electrical energy need in a building, through a change in heating technology, will result is a smaller flexible load potential for the building, as a larger share of electricity consumption will be used for high-priority loads (13). This problem is, however, outside of the scope of this thesis. All the while, the reader should keep this in mind.

Electrical vehicles (in 2030)

In the recent years, the number of electrical vehicles (EV) in Norway has increased, due to benefits and exemptions granted by the government.

By 2030, these incentives are expected to have made the EV a commercial alternative to cars with combustion engines. The increased penetration of EVs in the motor vehicle population is expected to cause great effects on the power grid, as well as possibilities. An EV charging profile generates peaks in household consumption, in a few hours of charging after the consumer return from work. However, for most consumers, there is no need to charge the car in that specific time frame. This opens up the possibility for load shifting to the low-demand night hours. An original EV-profile also evens out in the weekends (8) (1).

Incentives and the power of tariffs

A typical consumer does not concern herself with the well being of the electricity grid, making reduction or change of consumption a question of incentives. The greatest incentive is of course the potential economical savings a consumer might gain from participating in demand response. This can be induced through various types of tariffs provided for the consumer, for example through power tariffs or time-of-use rates. Power tariffs are already being used for large consumers, where power usage above normal level is priced with an extra charge, usually through different price steps. Time-of-use rates charges the customers according to the time of use, enabling higher prices in peak periods(14) (10).

2.3 Main findings from Tore Dyrendahl

Zero emission buildings (ZEBs) are one of the initiatives thought to be effective in the effort to collectively reduce the world's energy consumption. These are buildings which have a zero net energy consumption, due to energy efficient measures in the construction and production of their own power. Tore Dyrendahl (4) investigated the impacts of large scale implementation of ZEBs in the Norwegian power system, using the EMPS model. In several of the cases studied, a reduction in demand was introduced. Therefore, it is interesting to compare the modeling of the demand in his thesis to the modeling presented in this thesis. A short disclosure of the main findings of Tore Dyrendahl follows. Further information can be found in the master thesis (4).

Tore Dyrendahl uses a model setup provided by NVE in his studies, which is dissimilar to the Statnett base case used in this thesis. Accordingly, the exact output is not directly comparable. However, the conclusive trends found in the thesis due to certain changes in consumption profiles are comparable.

Modeling of demand profiles

The modeling of demand profiles in Dyrendahl's thesis aims to catch the effect of the variations of different inflow years. The main idea is that temperature dependency need to be captured at an hourly resolution to properly study the effects of a large implementation of ZEBs. Therefore, the load curves were constructed using an average maximum load as an upper limit. Furthermore, hourly local power production for the buildings was subtracted from this maximum limit. The resulting difference between maximum load and hourly distributed power production became the new profile.(4)

There are six model cases provided in Dyrendahl's thesis, differing in the share of ZEB, choice of heating technology, demand quantity and photo voltaic (PV) production. Three cases consist of a 50 % share of ZEB-buildings, but they are assigned different types of heating technology, resulting in different shares of consumption. The results disclosed in the next subsection are the cases compared to business as usual, where the original model setup developed by NVE was utilized.

Results

A large scale introduction of ZEBs in Norway showed significant impact on the Norwegian power system. For the case where heat pumps were the dominating heating technology in buildings, a 16 TWh difference in demand was observed compared to business as usual. This resulted in a reduction of average power prices, and the classic reduction of prices following the reservoir filling season was amplified. Furthermore, the large implementation of ZEBs inflicted a price collapse in wet years and a slight price increase for dry years.

When PV production was directly assigned the building loads, the model experienced a surplus of production, resulting in increase power export abroad. For the heat pump case mentioned above, there is a maximum export share of 33 % through the year, and the case experience no import (4).

3 The EMPS model

A study of the EMPS-model was preformed in the preliminary study for this thesis. The reader is therefore directed to the project report (15) for a closer description of the model functionality. However, a brief overview of the general model and area modeling is provided, followed a closer look at the role of demand in the model.

EFI's Multi-area Power-market Simulator is a favoured analytic tool for many market participants in the hydro dominated Norwegian and Nordic power system. The stochastic multi-area model aims to optimize the operations of a hydro-thermal power system, taking uncertainties such as future inflow and demand, thermal generation and international power exchange into consideration. Its strength lies within its ability to model and handle stochastic variables, for example temperature dependent demand or intermittent renewable resources. Among others, results from the EMPS model may include:

- Hydro system operation (reservoir levels, generation, flow, pumping)
- Power consumption and curtailment
- Market balance prices
- Socioeconomic results
- Emission

The model run consists of two phases; a strategy phase, in which the expected marginal water values are calculated, followed by a simulation phase, where these incremental water values are used to conduct area optimization for a sequence of different inflow years.

3.1 The area model

As the EMPS-name indicates, the model is composed of several subsystems or areas, defined by the input data from the user. These are often based on geographic specific conditions, such as hydrological factors, reservoir location, bottlenecks and/or ownership. Each area is assigned production units and demand, and they are interconnected through transmission lines with specified capacities, losses and transmission fees. An illustration of the area model can be seen in figure 3.1. The number of areas and the degree of detail in the modeling is user specific (15).

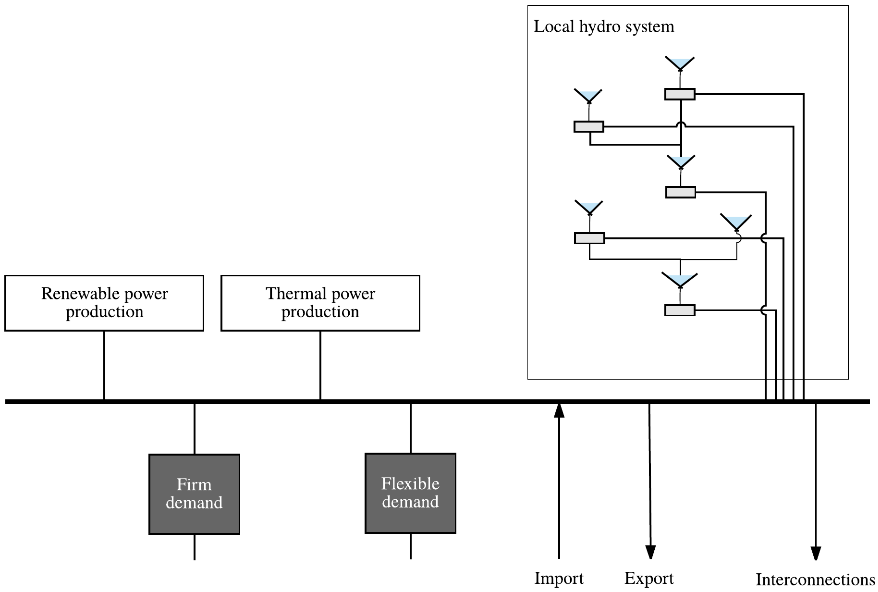

Figure 3.1: The schematic description of an aggregated area, including the components of supply, demand and interconnections

Power exchange between areas

There are two ways to model exchange between interconnected areas, either by spot exchange or through fixed contracts. These contracts have specified exchange volume and prices, and are used for certain periods. Spot exchange is based on the market clearing process, depending on prices, transmission capacities, losses and fees (15).

3.2 Demand in the EMPS model

The EMPS model divides demand into two different categories: *firm demand* and *flexible load demand*.

The latter, also called price elastic load demand, is used to model power intensive industry loads. Here, electricity is used in large quantities for production, making the load temperature independent. The price elastic load demand is modelled through interruptible power contracts, consisting of specific energy use in GWh and a disconnection price(15). Whenever the simulated area price exceeds the disconnection price, the load is instantly disconnected.

Firm demand is the fixed load demand, which must be supplied at all times. Traditionally this type of demand has been considered price-inelastic in the short term and only slightly elastic in the long term. (3) As explained in section 2.1, general consumption falls into this category and is thus modelled as firm demand. The modeling is done with firm power contracts, which normally includes five elements:

1. A predetermined annual quantity of energy to supply in GWh
2. An annual load profile for load distribution throughout the year
3. A weekly load profile for load distribution within each week
4. An ambient temperature profile (optional)
5. A price dependency (optional)

Load profiles

Each firm demand contract is assigned two load profiles. One annual profile in order to account for the seasonal variations in consumption throughout the year and a weekly profile to reflect the hourly variations within a week. The profiles consist of relative values for the share of electric consumption in each time step. These relative values can be deduced from historic consumption data, and they are usually based on a normalized inflow year.

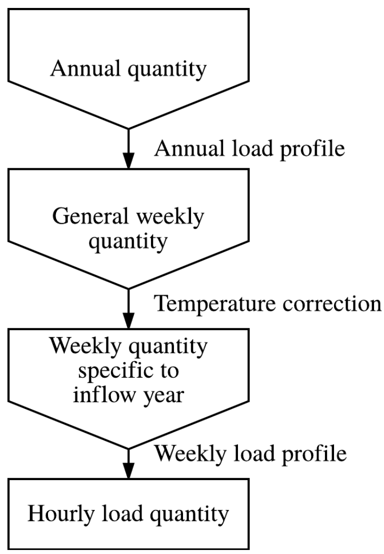

Figure 3.2: Handling of firm consumption in the EMPS model

The annual load profile has a weekly time step, assigning a share of the total consumption to each week of the year. The weekly load profile has an hourly time step, and it is applied after the weekly load has been corrected for temperature. This correction will shortly be explained. Both load profiles are exemplified in figure 3.3

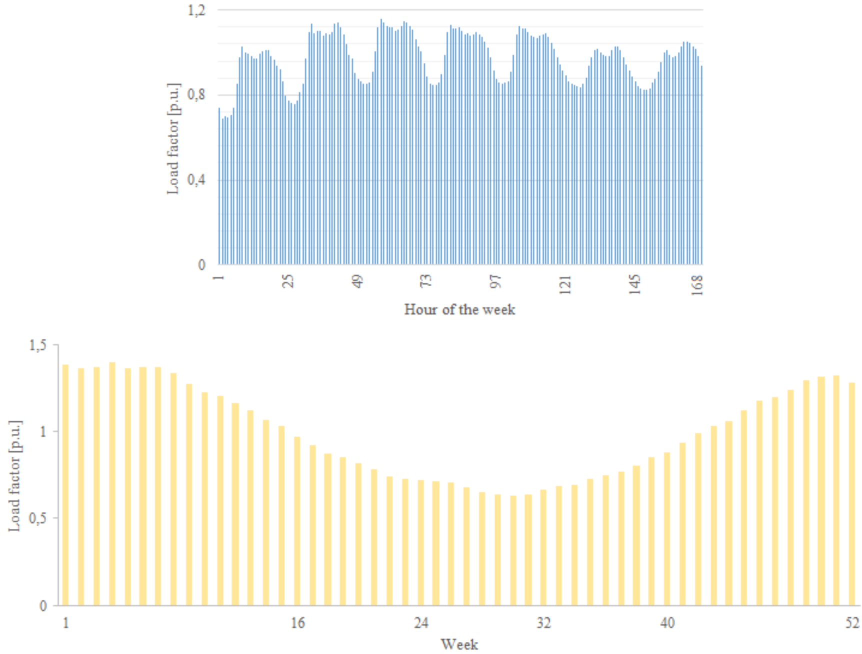

Figure 3.3: Weekly and annual load profiles indicating variations in consumption (15)

Temperature dependency

Firm power can be made temperature dependent with an ambient temperature profile, enabling a temperature correction of each weekly load through a year. Every week is assigned a relative temperature sensitivity, reflecting the percent change in consumption per degree Celsius (23). These values are generally derived from the correlation between historic temperature and electrical consumption in a specific area. Additionally, each contract is assigned an historic temperature series, after which the contract is corrected. These series corresponds to the inflow years through the simulation.

During simulation, the temperature correction is performed after the weekly distribution of annual demand. This is done using the following equation (23):

$$F(y,w) = (T_{mid}(w) - T(y,w)) \times \left(\frac{F_0(y,w) \times T_r(w)}{100} \right) + F_0(y,w) \quad (3.1)$$

$F(y,w)$	$=$	Temperature corrected load, year y, week w $[GWh]$
$T_{mid}(w)$	$=$	Average temperature for week w [°C]
$T(y,w)$	$=$	Temperature year y, week w [°C]
$F_0(y,w)$	$=$	Load assigned week w $[GWh]$
$T_r(w)$	$=$	Relative temp. sensitivity, week w [%/°C]
w	$=$	Simulation week
y	$=$	Inflow year

Before running the EMPS model, the user may define consumption profiles for the whole simulation period, relating them to the different inflow years. The less time consuming option is to make the firm demand temperature dependent as described in the above paragraph. This will then be the only variation in the input demand for the different inflow years. However, depending on the nature of the analysis, this is usually considered an acceptable shortcoming.

Price elasticity of firm demand

As explained in 2.1, general demand has traditionally been regarded as inelastic due to slow market price signals to the consumers. However, functions for limited price elasticity of firm demand has been developed, in accordance with the advancement of the power system. The price-demand interaction can be described either with a linear or an exponential function. A closer description of the latter can be found in appendix A.

During the simulation, the application of load price elasticity is the last alteration of firm demand before determination of the final hourly amount. As the elasticity is price dependent, it will vary the firm demand in each simulation according to the simulated prices. Therefore, create variations in firm demand for each inflow year, it will together with the temperature dependency.

Rationing

Rationing is the consequence of insufficient production capacity, making curtailments in firm demand necessary. This involuntary reduction of firm demand inflicts great socioeconomic costs to society, and in the

EMPS model it is represented by a rationing price. Since this is the last resort when market clearing is not obtained, the rationing price must be much higher than any other alternative in the model (3).

3.3 Challenges of modeling demand response in the EMPS model

When the EMPS model was developed, firm demand was considered close to inelastic. Some alterations have been made since, e.g. the implementation of price elasticity. However, the current modeling of firm demand in the EMPS model imposes some challenges when one wishes to model demand response.

Firstly, one could utilize the price elasticity of firm demand to simulate a price response for the consumer. However, the price elasticity can only be used for peak shaving, as the reduced consumption is not utilized at a later stage in the simulation process. Furthermore, the temperature correction is done on a weekly level, although great fluctuation in temperature, and hence consumption, can be found within the week. This limits the maximum hourly loads, and thus the creation of the high prices needed for price elasticity to operate.

If one wishes to utilize load shifting, it is possible to change the weekly load profile. This will, however, model demand response in a pre-determined way, and not as a response to price signals. With that, a reversed price effect will be the case, as the reduction in consumption will produce a reduction in prices, and not vice versa. In addition, if one wishes to use demand response to balance out the fluctuations of intermittent production such as wind and solar power, a match between hours of low production and shifts in consumption must be made in advance of simulation. This will again make demand response pre-determined, rather than a spontaneous reaction to the real-time situation of the power system. Yet, its effects will be present, although the preparatory work will be quite cumbersome.

As deduced above, there is no evident way of modeling demand response to catch its many benefits. However, the easiest way of modeling would be through alterations of the input demand profiles. In collaboration with Optimeering, Statnett has developed a tool to adapt their input profiles. This tool is utilized to model demand response in this thesis, and the next chapter will give an introduction to its many functions.

4 The Leopard model

The modeling of future demand profiles is an extensive task. It requires the consideration of numerous factors and how these factors interact. On assignment from Statnett, Optimeering has developed a tool called the Leopard model. It systematizes and correlate these factors, so that future demand and its distribution through the year can be projected. All new profiles implemented in this thesis are derived from the Leopard model. This chapter is based on the final report of Optimeering (21) and gives an introduction to the model, its underlying assumptions and how the future demand profiles have been put together.

The tool is developed to predict demand in both Norway and Sweden, and the projection approach differ somewhat for the two countries. As Norway is the focal point of this thesis, the reader is encouraged to consult the Optimeering report (21) to learn more about the Swedish demand. Hereafter this chapter will describe the Norwegian projection approach.

4.1 The model architecture

The basic model structure is illustrated in figure 4.1. Processing a mix of user-specific and set assumptions of drivers defining future development of demand, the Leopard model projects general consumption towards 2040, based on today's demand situation.

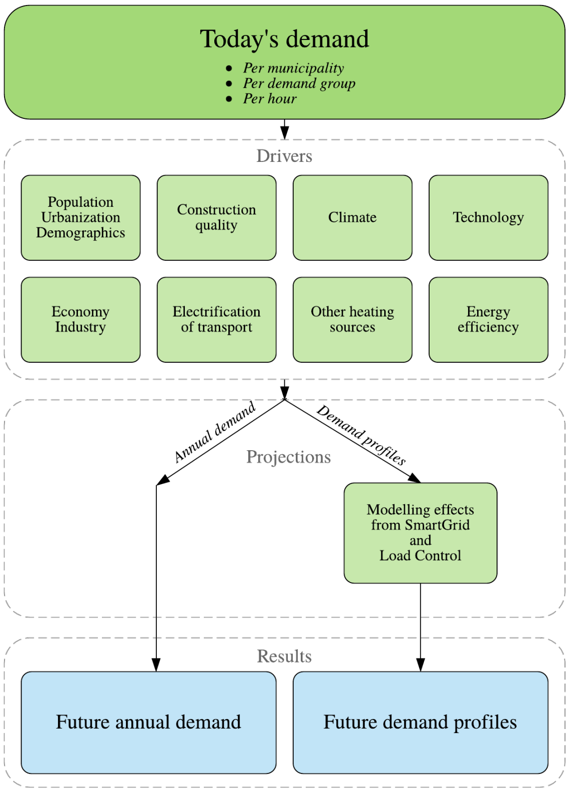

Figure 4.1: The Leopard model structure (20)

The output goal of the model is twofold and the projection is thus divided into two modules. Firstly, it aims to predict the future aggregated yearly demand of predefined consumption categories for every municipality in Norway and Sweden until 2040. This is done in module 1. Secondly, in module 2, it produces distinct hourly consumption profiles for each category. These profiles are adjusted from fixed profiles based on the input assumptions, and fit to the area and year in question. The user can also choose to run an optimization with regards to consumer flexibility.

The Leopard model is an Excel tool, consisting of worksheets and VBA-macros. The two modules are separated into two workbooks.

4.2 Future power consumption

Figure 4.1 depicts the drivers influencing future demand. The evaluation of these drivers are done on a basis of political directives and guidelines, historical development and profitability. The major development trends for general consumption deduced by Optimeering are highlighted in the following section.

Historical evolution of demand indicates that the increase in total consumption has leveled out. A continuation of this is expected into the future, as a result of difference in behavior within consumption categories. Whereas the share of electrical vehicles pushes demand related to transport up, a reduction in demand is predicted for buildings. This is due to energy efficiency measures, stricter construction demands, urbanization and an increased substitution of district heating to electrical heating. Consumption within the industry is assumed to experience a small increase, while demand for recreational homes and agriculture remain at today's levels.

It is important to note that the directives and guidelines usually encompass the total energy demand, making it difficult to estimate its effect on electrical power consumption. While a power reduction might be expected in accordance with the total energy reduction, an increase is just as likely if renewable electrical power is used to substitute more polluting sources. Simultaneously, the backlash effect might also lead to an increase in consumption. As demand is reduced power prices also go down, resulting in a small, new boost of consumption.

Due to a lack of quantitative data, the "how" of future consumption is difficult to predict. However, the roll-out of AMS to all residential customers is expected to have an impact on the daily consumption, subjecting households to a more flat consumption profile throughout the week. A change is not expected within the service or industry sector, as the hourly measuring units already are in place. Within the Leopard model, neither energy storage nor technological advancement is expected to partake in a change of consumption profiles due to a lack of profitability and small impact on hourly basis respectively.

Annual distribution of consumption will mainly be affected by climate change and an increase in building quality (21).

4.3 The modules

As mentioned, the model consists of two sub-modules. This section takes a closer look at both of them, but first some general assumptions are introduced.

Both modules are based on, and calculated for, a normalized temperature year, defined as the average of 30 years (21). This means that the relevant parameters going in and the model results are temperature corrected to reflect a normal consumption year. Furthermore, the underlying consumption data is obtained from the 2013 values.

The model only provides tools to process general consumption, excluding power intensive industry loads which falls under the definition of Statnett. As it is difficult to forecast how, and if, the general level of comfort (e.g. indoor temperature) within the population will evolve, it is assumed that it will reflect historic values. The power prices are also expected to remain fairly unchanged.

Module 1 - the annual demand projection

Module 1 aims to estimate future annual demand for the 13 different consumption categories seen in table 4.1, through evaluation of given parameters. The categories fall in under one of two consumption segments: residential and industrial/service demand. Together, residential and industrial/service demand make up the general consumption.

General consumption	
Residential demand	Industrial/Service demand
Housing EV households DP households Recreational residences Primary sector	Service buildings EV workplace DP service buildings Industrial buildings Industrial processes Services excluded buildings Supply and renovation Transport and storage

Table 4.1: The projected consumption categories

The module assesses nearly five thousand assumption parameters. These are organized within the dimensions of consumption categories, geography and time. The former dimension handles the specific drivers related to a particular demand, for example the rate of rehabilitation of houses or square meters per employee in service buildings. Meanwhile, in the geography dimension, geographically specific assumptions are done on three levels:

- Municipal, e.g. population growth
- County, e.g. annual rate of industrial consumption
- National, e.g. electrical share within households

This layering have been based on available data and the importance of each parameter. Lastly, the time dimension describes the periodic intervals for which calculations are done; every fifth year from 2015 to 2040.

Naturally, the three dimensions are codependent. This can be exemplified by examining the extrapolation of primary sector demand. By combining the annual change rates on a county level with the total municipal consumption, the module calculates demand per municipality within the primary sector category for each of the six future years.

The user of the module is of course able to alter most of the different assumption parameters in the module. There is, however, a hierarchy of parameter rigidity, based on the probability of change connected to said parameter. For example, the electrical share within households might be changed frequently by the user, while the temperature sensitivity of household consumption is relatively set.

Module 2 - the adaptation of demand profiles

Whereas module 1 predicts future amounts of consumption, module 2 estimates how this consumption is distributed over the hours in a year. The module is designed to estimate both daily and annual profiles, both with an hourly resolution.

Through profound analysis of the available consumption data Optimeering has developed basic descriptive profiles, which form the foundation in module 2. These are distinct for three different consumption segments; residential, primary sector and the service sector. As in module 1, the profiles are linked to time, geography and the consumption segments aforementioned.

Daily consumption profiles

Due to a lack of underlying data, geographic variations are not taken into account in the creation of the daily profiles. Therefore it is assumed that a consumer in the rural north of Norway will act in the same way as an urban consumer in e.g. Bergen. However, the three consumption segments are treated slightly different. The service sector is regarded as temperature independent, resulting in two daily profiles to distinguish between business days and weekends. On the other hand, the primary sector profiles do not account for the day of the week, as agricultural demand is the same throughout the week. It is, however, temperature dependent, so four separate daily profiles are made for each season. Lastly eight daily profiles are made for residential consumption, as it depends on both time of week and the seasons. Figure 4.2 illustrates a schematic overview of the twelve descriptive daily profiles.

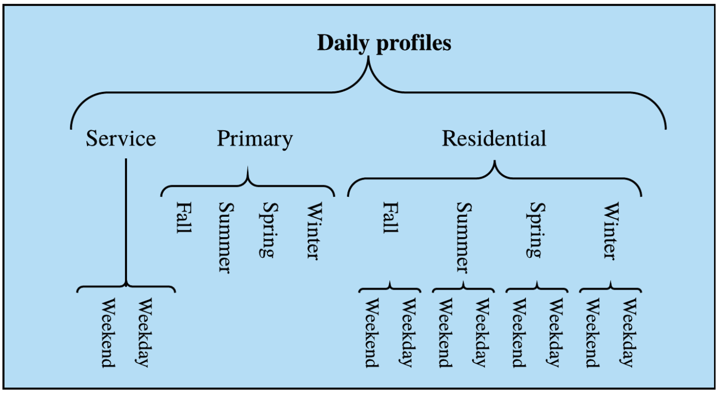

Figure 4.2: Schematic overview of daily profiles generated in the Leopard module

Only the residential daily profiles are adapted, due to the expected change in behavior following the installation of AMS, explained in section 4.2. How this is done will be explained shortly. Since no change of behavior is expected for the remaining categories, they stay equal to the basic descriptive profiles through the whole processing period. This means that the non-residential daily profiles for 2015 will be exactly the same as the profiles for 2030.

Annual consumption profiles

The aforementioned neglected difference in consumption behavior due to geographic dissimilarities, is accounted for in the adaption of the annual profiles. Here it is the dominating dimension, as they aim to catch how climate change and construction quality affect yearly consumption. The latter effect means that an adaptation is done for all three segments. Based on the climate zones of Koppen (see (21) for further explanation), residential and primary sector profiles are made for coastal, mainland and arctic climate, resulting in three annual profiles per segment. The service segment is treated differently, creating two profiles which distinguish between a small share and a big share of service activity. For profiles with a small share, industrial activity will dominate the service segment, while the latter is dominated by service activity. This results in two different profiles. Altogether, the Leopard model produces seven distinct annual profiles. A schematic overview is presented in figure 4.3.

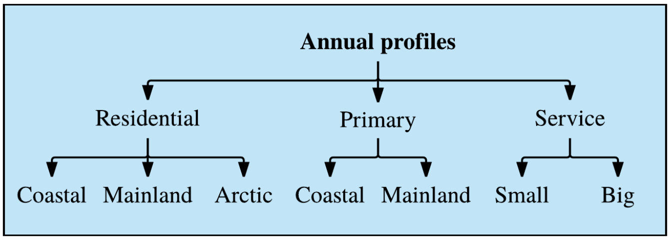

Figure 4.3: Schematic overview of annual profiles generated in the Leopard module

Adaptation of residential daily profiles

The adaptation of residential daily profiles is done to account for the implementation of smart grid solutions and load control. Therefore, two influential factors are considered; time and flexible loads. Time account for which periodic interval calculations are done, namely each every fifth year from 2015 to 2040. Flexible loads, on the other hand, account for the loads which are influenced by demand flexibility, though not by demand response exclusively. These loads are divided into three subcategories, each with a predetermined descriptive daily profile:

- Household consumption used for electrical vehicles
- Household consumption used for heating water
- Rate of newly built (and rehabilitation of) housing

In addition to having descriptive profiles, the two first subcategories are also provided with a share of flexibility for each hour, for weekdays and weekends. E.g. in the peak hour 4 p.m., only 3 % of electrical vehicle load can be moved, while a less strained hour in the middle of the night have a flexibility share of 10 %. These values are again derived based on historical data. The flexibility present in these profiles is, as mentioned previously, not exclusively provided by demand response, though for electrical vehicles and heating of water it is assumed to be the dominating effect, regardless of how it is implemented. The rate of newly built housing accounts for a reduction in demand, due to better insulation and energy efficiency measures which lead to strategic conservation.

Within the newly build rate category, several parameters derived from directives and guidelines are provided. For every time period a rate of newly built housing can be specified. This is a percentage used to determine how much of the profile that should be adapted according to the new build parameters. E.g. with a 30 % share of newly built housing in 2020 and 20 % in 2025, 30 % of the original profile will firstly be adapted according to the new build parameters for 2020. In the next iteration, 20 % of the new profile will be adapted according to the 2025 specifications. The resulting profile for 2025 will then comprise the specific effects of new build for both time periods.

The optimal residential profile is found through optimization of the flexible load profiles in Excel. Using the flexible share denoted each hour as limits, the optimization move Hot water and EV demand, aiming to flatten the total residential consumption profile. The objective function is defined based on the descriptive residential profile, and the flexible loads interact to find a feasible solution. When the optimization is finished, optimal profiles for Hot Water, Electrical Vehicles and non-flexible load are found and added together to a single residential profile. This process is repeated for the eight daily residential profiles in all time periods.

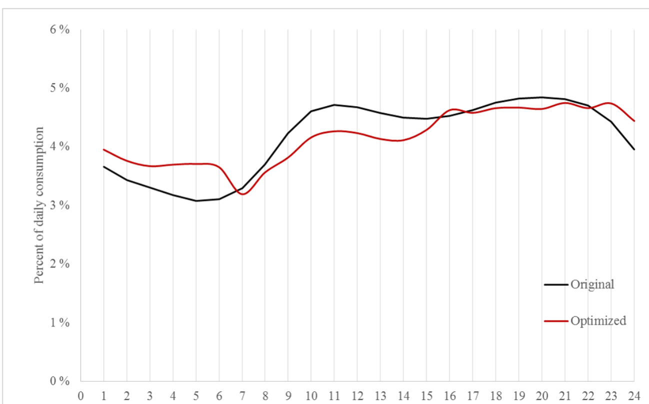

Figure 4.4: 24-hour residential daily profile, a weekend in the summer

A residential profile before and after optimization is exemplified in figure 4.4. In this figure, it is evident that peaks of consumption have been moved and that the profile experiences smaller variations after the optimization.

4.4 Output profiles from the Leopard model

In module 1 of the model, the output consists of projected annual consumption quantities for each consumption category, municipal and year in the model. Furthermore, in module 2, the annual and weekly profiles are assembled to annual profiles of 8760 hourly entries, where all dimensions are accounted for. In the transitions between seasons, a smoothing function is utilized. Holidays are treated as weekends. 2018 is used as the template year for the assembly, as it begins on a Monday and is not a leap year.

By combination of the two modules, the Leopard model delivers demand profiles assigning each hour through the year with its respective energy consumption quantity. A profile for each municipality in Norway is provided, enabling aggregation on different levels, for example into counties or Nord Pool price areas. As the model is developed for Statnett and their analysis, aggregation into the EMPS areas is possible.

The arrival of the municipal demand profile is achieved by weighing the individual profiles for each consumption category in accordance with the geographically specific parameters for each municipal. Furthermore, the projected annual amount is distributed, resulting in the demand profile described in the above paragraph. During the aggregation, the constituting municipals are added together to generate an aggregated demand profile where all input parameters are accounted for.

5 The model setup and cases

The model setup used in this thesis is based on a 2030 base case developed by Statnett. Five cases have been developed, where different modeling of general consumption has been implemented. This chapter firstly gives an introduction to the original 2030 base case. Then a description of the five simulation cases is provided, where both the new modeling of demand and the deduction of its profiles are explained.

5.1 The data set - 2030 base case

Through analysis of the future development trends in the power and energy systems in Europe and the Nordic region, Statnett predicts future modeling scenarios for the EMPS model. The model setup chosen for this thesis is the base case for 2030 developed by Statnett. As the main objective of this thesis is to evaluate the effect of modeling demand response, one could argue that a data set representing the present, thus involving less uncertainties, would be preferable. However, to study the incentives of DR to the consumer, it is appropriate to choose a model setup reflecting the proper characteristics of the power system. This is ensured with the 2030 base case, if one predict that the full utilization of smart meters and the necessary market functions will be in place by then.

Section 5.1 is based on the long term market analyses report presented by Statnett in 2016 (8).

The model set up

The 2030 base case is composed of 34 areas, as seen from figure 5.1. Based on linked water ways for hydro power, Norway is divided into 15 price areas, while a less detailed division is done for the remaining Nordic region. Sweden consists of four areas and Finland and Denmark are split in two. The Nordic areas are modelled in more detail than the remaining 11 price areas representing all interconnected countries to the Nordic region.

To limit the scope, and thus computation time, of the model, the non-Nordic countries with a strong influence on the Nordic power prices are modelled with pre-simulated price series. These are Great Britain, the Netherlands, Germany, Poland and Russia. The pre-simulated price series are based on the assumed evolution of the continental power system, which mean they reflect the types of production unites utilized in Europe. In 2030, a higher penetration of intermittent power production is expected, resulting in fewer hours of utilization of expensive thermal power production. Additionally, a higher share of hours with prices dropping close to zero will occur, due to solar or wind production, or the marginal cost of lignite or nuclear, determining the power price (8).

A simplified modeling is done for the remaining non-Nordic areas.

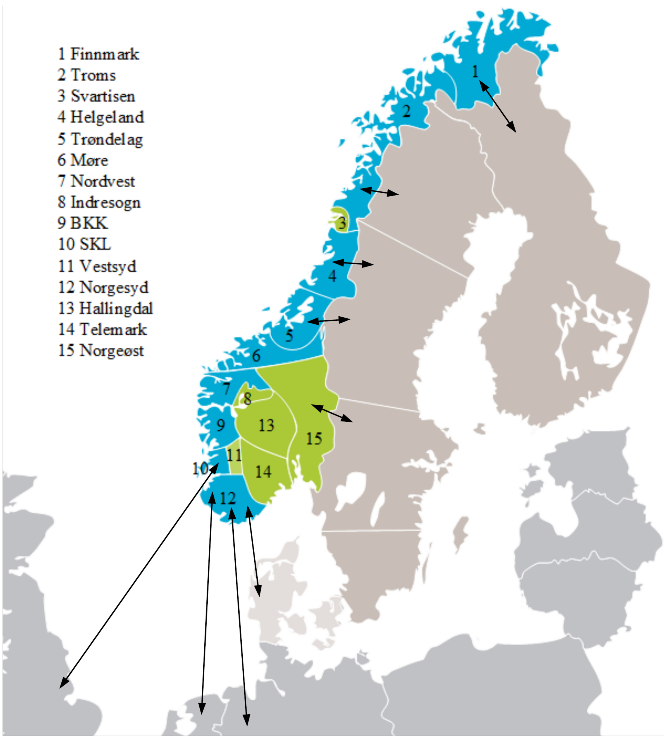

Figure 5.1: The EMPS areas and cross-border connections

The areas are connected through transmission lines, each assigned the actual transmission capacity to and from the respective area. As the data set represents the situation for 2030, the planned interconnections from Norway to England, "North Sea Link", and from Norway to Germany, "NordLink", are also modelled at full capacity. Additionally, transmission lines connecting Norway to Sweden and Denmark are modelled. Again, at correct and full capacity.

To enable a wide range of outcomes for the 2030 power system, the simulation runs for a period of 25 years, from 1988 to 2012. Hydrological data from this period is used to describe yearly inflow and temperature. The resolution of the model is 168 hours per week, meaning that each hour is handled with a separate market clearance. Among other advantages, this facilitates a more detailed analysis of peak periods, as parameters such as price and firm demand are given for each hour.

Production

Statnett predicts a decrease in regulated thermal and nuclear production and an increase in intermittent renewable production. Even though Finland is building new nuclear reactors in the North, Denmark is phasing out thermal production and Sweden has several reactors shutting down due to age. At the same, time 30 TWh of new renewable power production will be installed, in the form of hydro-, wind- and solar power. (15)

Firm demand

In the base case for 2030, two firm demand contracts are modelled in the Nordic region; general consumption and electrical vehicles. The transmission losses are also modelled as firm demand contracts, further explained in section 5.1.

The annual and weekly load profiles provided for the general consumption are country-specific. In Norway, Sweden and Finland the areas are made temperature dependent through ambient temperature profiles, as the main portion of the electrical consumption is used for space heating. However, this is not the case for Denmark, leaving their consumption temperature independent. While all the three profiles are identical for all areas within a country, the fixed yearly quantity is specific to each area. These amounts are like most inputs based on historical data.

Electrical vehicles (EV) are modelled explicitly, with area-specific yearly quantities and flat demand profiles, splitting the consumption evenly over the hours through the year. EVs are not made temperature dependent. The assumption of flat weekly profiles is a clear simplification of reality, as consumption related to EVs experience prominent peaks in some hours of the day (1). However, the small magnitude of the original EV input in the data set minimize the simplification, as the effects of general consumption are dominant.

In the Norwegian areas the firm consumption is modelled as slightly price elastic, using the exponential function approach described in appendix A. The price threshold and the rate at which the consumers are willing to alter their demand when prices exceed this threshold is set to $P_n = 85\ e/MWh$ and $e = 3\%$ respectively. The price threshold is simply based on a predicted high price level for 2030, deduced in the long term market analysis report (8). Meanwhile, a quantitative study of short term price sensitivity in general consumption conducted by ECON (5), arrived at said rate of alteration.

An upper limit for the consumers willingness to pay is modelled at 500 €$/MWh$. Should prices overrun this limit the model will have to utilize to rationing.

Flexible demand

If one disregards the price elasticity of the modelled firm demand, the only flexible demand originally found in the data set, is the power intensive industry.

This consumption segment is modelled with interruptible power contracts, with a disconnection price of 375 €$/MWh$. In another study conducted by ECON (6), investigating the flexibility in industrial consumption, an upper limit for the industries willingness to pay was found to be 300 øre$/kWh$. In the data set this has been translated to 375 e/MWh, and it is used as the only limit instead of an upper limit. This is due to uncertainty in the actual short term flexibility of the industry.

All power intensive customers are modelled as individual contracts, with flat demand profiles.

Rationing

The rationing price is the highest price limit in the model, set at 900 e/MWh. Normally, this would be the highest reachable price in the model. In practice, the power price never reaches this level, due to the large amounts of flexible power intensive loads present in the data set. Therefore, the practical maximum price can be regarded as 375 e/MWh.

Losses

The transmission line losses are not accounted for during the simulation with the EMPS model. Consequently, they are modelled explicitly by adding a firm demand contract with a precalculated loss amount in GWh. These losses are also provided with a price elasticity through the exponential function approach, with a price threshold of 45 e/MWh and a change rate of 3%. Normally, this price threshold should be similar to the general consumption threshold. Yet, in the data set adaptation for 2030, this parameter was not changed due to a mistake. Therefore, it reflects the 2016 price threshold, but as the losses account for such a small amount of the total firm consumption it is an acceptable error.

5.2 The five cases

The current modeling of firm demand has a rough resolution, based on historical modeling. General consumption is grouped together, with the exception of electrical vehicles.

If properly facilitated, demand response will be present in all segments of general consumption. An interconnected utilization is necessary to achieve a reduction of peak loads and consequently, reducing the grid strain. However, the effects from each segment will differ, and to catch and distinguish these a partitioning of general consumption is needed. This is an extensive and cumbersome task, so in accordance with the scope of this thesis, DR within the residential sector, and thus the modeling of this sector, has been in focus.

There are a number of different ways to alter general consumption. In this thesis the Leopard model has formed the foundation of the subdivisions. Within this model, it is possible to deduce several approaches. Therefore, five different cases have been created, to investigate different ways of modeling demand response within the residential sector. The cases are defined based on two criteria; the subdivision of firm demand contracts and the way of deducing the demand profiles. Both criteria have been determined by the layout and limitations of the Leopard model and its handling of demand response. Table 5.1 shows an overview of the five different modeling cases, focusing on the implemented firm demand contracts.

Case	**Subdivision of firm demand**	**Norwegian annual quantity**	**Area specific profiles**	**Temperature dependency**
Historical	General consumption	81.4 TWh	No	Yes
	EV	3.1 TWh	No	No
Flat	General consumption	81.4 TWh	No	Yes
	EV	3.1 TWh	Yes	No
AreaAgg	General consumption	84.5 TWh	Yes	Yes
OptFlex	Households	42.4 TWh	Geo. dependent	Yes
	Primary sector	2.0 TWh	Geo. dependent	Yes
	Service sector	40.0 TWh	Geo. dependent	Yes
Separation	Households	34.2 TWh	Geo. dependent	Yes
	Primary	2.0 TWh	Geo. dependent	Yes
	Service Sector	40.0 TWh	Geo. dependent	Yes
	Hot water	5.6 TWh	Geo. dependent	No
	EV	3.9 TWh	Geo. dependent	No

Table 5.1: The five different cases evaluated in this thesis

The *Historical* and *Flat* cases should be regarded as outer limits in the analysis, reflecting the best and worst case scenarios of utilizing the potential of demand response. Although *Historical* is regarded as the worst case scenario in this thesis, the power system might evolve in other and more grievous ways in the future. The base case is developed by Statnett to reflect the most likely power system development. However, with the great amounts of uncertainties present, a different development might take place.

In the three remaining cases a plausible utilization of DR in 2030 is modelled, even though they model firm demand differently. All five cases will be further explained in the following paragraphs, including both the setup of each case and the deduction of their demand profiles.

In addition to the five modelled cases, the results will be evaluated in regards to the findings from the master thesis of Tore Dyrendahl, summarized in section 2.3.

The Primary and Service sector

Before each case is explained in detail, a disclosure of the "non-flexible" categories is in order. The primary and service sector are modelled without flexibility in all relevant cases; *AreaAgg*, *OptFlex* and *Separation*. This means that their consumption profiles remain the same in all cases, although there is a slight difference in the annual consumption amounts due to EVs. This will be further explained for each case. Both the primary and the service sector have demand response potential, yet the scope of this thesis encompass only the residential sector. Therefore, it is reasonable to leave the other sectors unchanged and without demand response, to better capture and study DR within the residential sector.

Historical and Flat profiles

In the historical case, *Historical*, the modeling of firm demand is as described in section 5.1, with the exception of the consumption quantities. These have been altered to the annual amounts projected by the Leopard model, to enable grounds for comparison to the remaining cases. Consequently, some areas experience a noteworthy increase in consumption, while there is a decrease in others. This geographical shift of consumption is probably due to a difference in definition of constituting municipals per EMPS area. All together the Leopard model reduces consumption in Norway by about $3000GWH$ compared to Statnetts base case.

The demand profiles set by Statnett do not account for any flexibility, making *Historical* the "worst case" scenario, where no demand response is utilized.

Opposite, there is the *Flat* case, where consumption is distributed evenly through the week. The notion here is that through utilizing DR, consumption is increased in low-load hours and decreased in peak hours, rendering a non-fluctuating consumption through the week, thus making it the "best case" scenario. To model this, a simple alteration of the weekly load profile of general consumption was done, making it flat for all weeks through the year. Meanwhile, the annual profile remains unchanged and the annual amounts are equal to the *Historical* case.

***AreaAgg* - Area aggregated profiles**

As explained in section 4.4, output from the Leopard model is a set of aggregated consumption profiles when the model is run all the way thorugh. To test these profiles, the *AreaAgg* case was made, using the original output for 2030 as a basis. These profiles encompass all Norwegian firm consumption, including electrical vehicles, resulting in only one firm demand contract, namely *general consumption*. The contracts were assigned the annual quantity of total firm demand for each area, projected in the Leopard model.

As explained in Chapter 4, the consumption profiles consist of 8760 entries of the specific hourly energy consumption through the year. They are made area specific to each Norwegian EMPS area, through aggregation of the constituting municipal profiles. While the Leopard profiles are made up of energy quantities per hour, the input profiles to the EMPS model consists of relative values. In addition, the annual time frame in the Leopard model is 365 days, whereas the EMPS model operates with 52 weeks, equaling 364 days. For this reason, some alterations was in order.

To create the annual EMPS profiles, the hourly entries were summarized into weekly amounts and divided by average weekly consumption of the year. This amounts to profiles of 52 relative weekly entries.

The total weekly amounts were also utilized to adapt the weekly load profiles, to calculate an hourly average for each week through the year. Furthermore, the original hourly entries were divided by the hourly average of their respective week. The result was 52 distinct profiles, of 168 relative entries per week. Both profiles have neglected the 365th day of the year.

The general consumption is made temperature and price dependent, retaining the temperature profile and the price elasticity modeling provided in the 2030 base case.

While the original output from the Leopard model assembles all factors concerning future demand, a separation of these factors is in some cases desirable. E.g. to illuminate the aforementioned difference in effect and potential of demand response within the various consumption categories. The following cases are created to reflect just this.

OptFlex **- Optimization of flexible demand**

The *OptFlex* case divides general consumption into its main consumption segments; the residential, primary and service sector. Although this is a natural subdivision of firm demand, it is also based on practical considerations regarding the Leopard model. Through the profile adaptation process in Module 2, it is possible to extract profiles specific to each of these segments, as they are handled separately prior to the aggregation into a general consumption profile.

As seen in table 5.1, the residential sector is renamed *Households* for simplicity. In regards to table 4.1, this contract encompasses housing, recreational residences and EV and DP households, and is thus assigned the total projected annual amount of these subcategories. The primary sector is extracted from residential demand, while all subcategories (in table 4.1) of the service sector are aggregated. Consequently, three firm demand contracts remain; *Households*, *Primary* and *Service sector*.

The Leopard model assembles all the respective consumption profiles for a municipal prior to the aggregation into EMPS areas. According to geographical specifications, both annual and weekly profiles are adapted and weighted to fit the municipal in question. Afterwards, all municipals are aggregated into their respective EMPS-areas. Both annual and weekly profiles for the three sectors were extracted from the Leopard model for 2030 before the geographic adaptation. The extracted Leopard profiles were thus in the general form described in section 4.3, in need of adjustment to fit the EMPS model.

In the process of adjusting the Leopard model to match the EMPS format, three operations were performed:

1. Establishing geographic affiliation of EMPS areas, with respect to the annual profiles
2. Assembly of daily into weekly profiles for each demand contract
3. Conversion of profiles into relative values

Firstly, each EMPS area were denoted either a coastal or a mainland annual profile for the residential and the primary sector. This was simply decided according to figure 3.1, where the green areas are classified as mainland, and the blue are classified as coastal areas. Furthermore, the share of service activity were calculated for each EMPS area, based on the projected annual consumption amounts summarized in table 4.1. The service demand contract in each area with a service activity of 70 % or higher were denoted big share annual profiles, while the remaining areas were given small share annual profiles.

After assigning each EMPS area with their proper annual profile classification, the daily profiles of the three consumption segments were assembled to weekly profiles. These profiles are not geographic specific, resulting in similar profiles for *Households*, *Primary* and *Service sector* in each area.

For the *Households* daily profile, the adaptation and optimization described in section 4.3 were utilized. Demand response was thus accounted for through load shifting. Furthermore, a new built rate of 30 % was specified for each five-year iteration from 2015 to 2030. This is a quite high share of new build and rehabilitation of housing, and it results in a great share of flexibility. The optimistic parameter was chosen based on the scope of this thesis, to (hopefully) explicitly highlight the effects of input demand response in the EMPS model.

Finally both annual and weekly profiles were adapted to relative values of weekly and annual demand. A combined profile for households is displayed in figure 5.2, where the weekly average represent the annual profile. A weekly profile for the winter is depicted in figure 5.4.

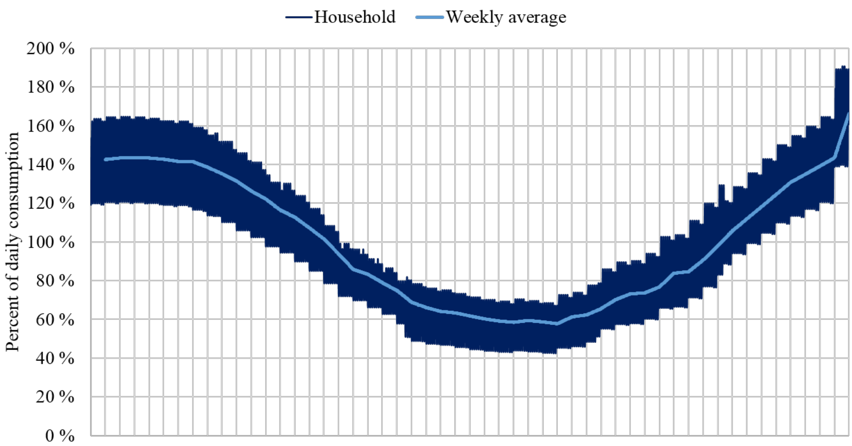

Figure 5.2: Combined weekly and annual profile for household consumption in *OptFlex*

All three contracts were made price and temperature dependent in the same way as the *Historical* general consumption. The fairness of assigning equal price elasticity to all contracts is questionable. Nevertheless, the specific price elasticity of primary and service demand is outside the scope of this thesis, but it could not be ignored altogether: thus the resulting modeling. However, the high price level assigned to the elasticity is not reached often enough to impact the results noteworthy. The temperature dependency will be further discussed in section 3.2.

Separation - Separation of flexible and firm demand

In the final case, *Separation*, the flexible and non-flexible parts of residential demand are separated. *Hot water* and *EV* are modelled as separate contracts containing the flexible share of household demand, while the remaining *Households* contract only encompassed non-flexible demand. This division will be explained in the following section.

The *Primary* and *Service* contracts are modelled similar to the *OptFlex* case, with only a small alteration in the service contract. Due to the modeling of EV as an individual contract, the annual projected amount of EV workplace is extracted. This results in a slightly smaller annual service sector demand.

In accordance to table 4.1, the annual amounts of EVs are found by adding EV household and EV workplace. As hot water is not a separate category in module 1 of the Leopard module, its annual amount had to be extracted from the total household demand, which sans EVs includes housing, DP and recreational residences. According to the REMODECE project (2), about 15 % of Norwegian household demand is used to heat water. Accordingly, 15% of projected household demand was denoted the *hot water* contract, while the remaining 85 % was assigned *Households*.

During the creation of this case, the assigning of annual profiles proved to be somewhat challenging. Although *Primary* and *Service* retained the profiles assigned in OptFlex, the remaining three contracts were less straightforward. The Households contract kept the annual profile from OptFlex, while EV and Hot water were assigned flat annual profiles. It was thus assumed that the share of electricity used for water heating and EV charging remain equal throughout the year, leaving the non-flexible demand unmoved by the extraction of flexible loads. At the same time, the flat profiles of EV and hot water indicate a consumption unaffected by the seasons. This is a simplification, where the effects of temperature on e.g. the duration time of EV batteries and heating of water are neglected.

The optimization of the daily residential profiles, disclosed in Chapter 4, produce optimal profiles for all three subcategories. These were extracted and furthermore assembled and converted to relative values in the same way as in subsection 5.2. Figure 5.3 depicts the resulting profiles for EV and Hot Water. The EV profile is very volatile, and show that EV's will contribute to demand during the evening and night hours. However, the profiles are equal for all days in the week, an assumption that is less accurate as Bilko explains in her master thesis

(1). At the same time, *Hot Water* differentiates between weekend and weekdays, and it shows a less violent fluctuation with smaller but more numerous peaks. The water heater is boosted at 08:00 and again at 23:00, complimenting the consumption behavior of the remaining residential consumption. When added together with the *Households* profile in 5.4, the total residential profile will be evened out.

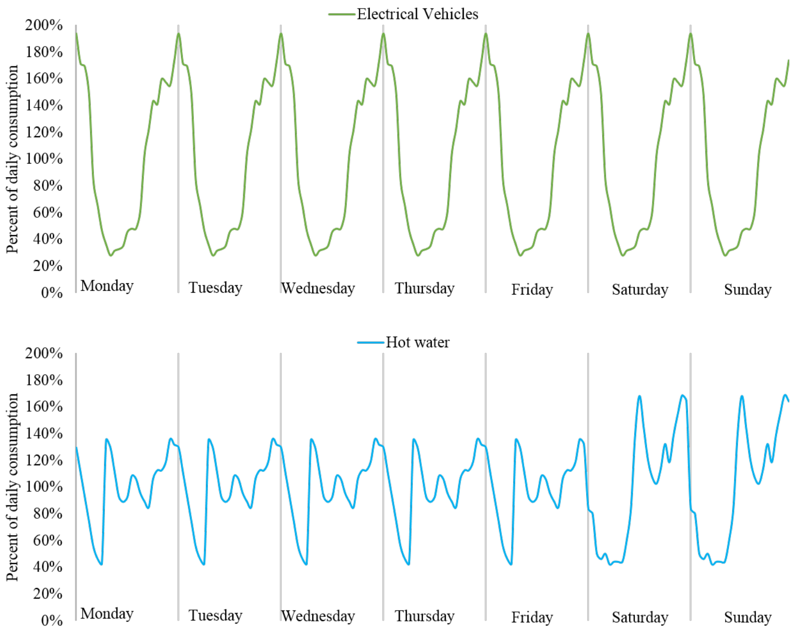

Figure 5.3: Optimized weekly profiles for Electrical vehicles

Weekly profiles of a winter week for all cases are rendered in figure 5.4. A shortcoming in the Leopard model is that the seasonal variations for flexible demand are only accounted for when the weekly and annual profiles are combined, meaning no seasonal variations are applied in the daily profiles. Even if the flexible consumption is not directly sensitive to temperature, it will be sensitive to a change in consumer behavior as a result of seasonal variations. However, as explained in subsection 4.2 it is difficult to track these patterns, which in turn results in a need for simplifications.

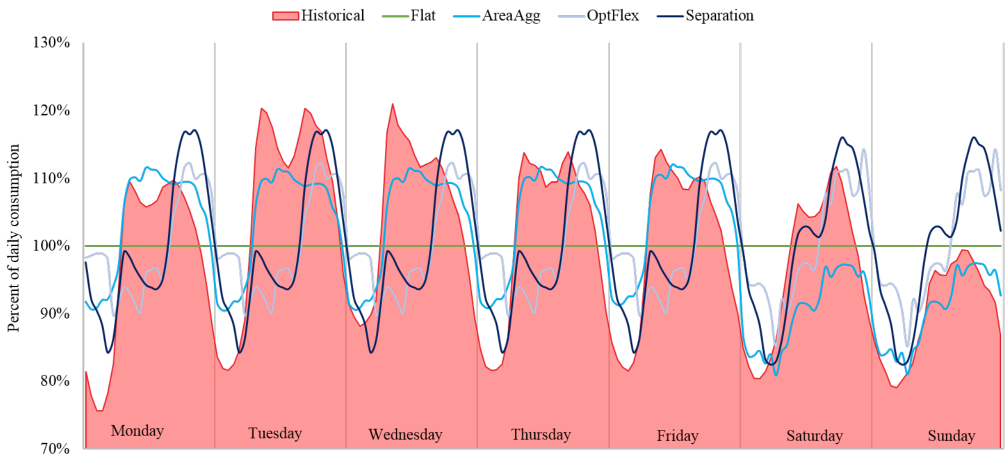

Figure 5.4: Weekly profiles of a winter week (49) for all five cases

Households, *Hot water*, and *EV* were all provided with the usual price elasticity. The latter two were naturally not made dependent on temperature, as its effect was neglected. Meanwhile, a new temperature profile was calculated for the non-flexible household, further explained in the following chapter.

Temperature dependency

Close to all of the firm demand contracts in every case are given the default temperature dependency from Statnett base case 2030, except the residential profiles in *Separation*. In *Historical*, *Flat* and *AreaAgg*, the firm consumption is modelled as general consumption, making the original temperature profile a valid choice. For *OptFlex* and *Separation* however, it is less accurate to assign all contracts with the same temperature dependency. Yet, this was done due to a lack of other options and the aforementioned scope and time limitations.

The temperature profile developed by Statnett for 2030 is based on historical data for consumption and temperature, and it is made to fit general consumption. Accordingly, this collective profile assembles the temperature dependency of all subcategories to general demand, even though they differ. As some temperature effects are contradicting, the resulting temperature profile might be too flat for some subcategories and too volatile for others. An adaptation could have been done, for instance by adapting the existing profile in accordance to the composition of the different sectors within general demand. However, due to a lack of data this was not possible for this thesis.

In regards to the primary and service sector in *OptFlex* and *Separation*, an option was to leave them temperature independent. This was however unrealistic, as a great part of their electrical consumption is space heating. The share of space heating is not necessarily equal the household share, but due to the limitations explained above, this modeling was considered satisfactory.

The *Households* temperature dependency in *Optflex* was modelled with the general consumption profile, while in *Separation* it was altered in accordance with the extraction of *Hot Water*. When 15 % of the temperature independent consumption is drawn out, the remaining demand will be left more dependent on ambient temperature. Therefore, the household temperature profile in *Separation* was adjusted to be 15 % more temperature dependent than the original profile.

With these simplification for temperature dependency one generates a less exact result concerning firm demand, yet it is considered satisfactory in light of the scope of this thesis.

6 Evaluation criteria for the analysis

As mentioned in chapter 3, a wide range of results can be obtained from the EMPS model. In this thesis the following results have been considered appropriate to study the effects of input demand response in the EMPS model:

- Firm consumption
- Power prices
- Cross-border power exchange
- Profitability for the consumer
- Socioeconomic surplus

While the results for the first three points are directly collected from the model, *Profitability for the consumer* and *Socioeconomic surplus* have been deduced using output data. How these evaluation criteria have been calculated will be explained in this chapter, followed by a disclosure of limitations and sources of errors.

6.1 Profitability for the consumer

The two-way communication and real time reporting mechanisms through smart meters are thought to be important drivers for demand response. By exposing the consumer to real time prices, the utility encourages the consumer to reduce their consumption in high price periods, which often coincides with peak load periods. This exposure alone is not thought to trigger large amounts of load shifting or clipping, due to the combination of consistently low Nordic power prices and the affluent Norwegian consumers unwillingness for discomfort (15). However, it will accumulate savings for the customer, making profitability to the consumer a valid evaluation criterion. Therefore, a study of the effects of power prices in regards to profitability has been conducted.

To study the profitability for consumers, an average household customer has been considered. In 2012, the average Norwegian household consumed 16044 kWh of electrical power (25). Though there are some regional differences reflecting urban versus rural conditions, the average consumption has formed the basis for the analysis. Additionally, the slight demand reduction in 2030 in the residential sector has been neglected, resulting in the study of a suburban customer living in a non-rehabilitated house.

The annual consumption has been distributed through the hours of a year with the adjusted demand profiles. In the cases *Historical*, *Flat* and *AreaAgg*, general consumption profiles were utilized, while the household profiles have been used in *OptFlex* and *Separation*. In the latter case, 15 % of the household consumption was denoted to hot water, which was distributed with its respective profile and added to the remaining household consumption. All cases were temperature corrected in accordance with the procedure used in the EMPS simulations, described in section 3.2.

The resulting annual cost of consumption was found by multiplication of distributed consumption and their respective hourly prices. Two scenarios were considered:

1. Case consumption and *Historical* prices.
2. Case consumption and case specific prices.

When the consumption decreases it is natural to assume that the power prices will decrease, due to a leftward shift of the market clearing cross. This will lead to a lower savings potential for consumers, which might again push the prices up slightly as consumption increase again. The two scenarios aim to first study how much a forward customer could save in the historical case if consumption is reduced, then investigate saving potential in each case. The former effect is studied in scenario one, using historical prices to calculate both costs. The same procedure is used in scenario two to describe the second effect, only here the annual cost of consumption of each case is subtracted from the historical cost. Both calculations are described with the following equations where S equals annual savings to the consumer, C and P is the consumption and price for each hour through the year.

$$S_{SC2} = \sum_{h=1}^{8736} C_{Historical,h} \times P_{Historical,h} - \sum_{h=1}^{8736} C_{AreaAgg,h} \times P_{Historical,h} \quad (6.1)$$

$$S_{SC1} = \sum_{h=1}^{8736} C_{Historical,h} \times P_{Historical,h} - \sum_{h=1}^{8736} C_{AreaAgg,h} \times P_{AreaAgg,h} \quad (6.2)$$

One might question the feasibility of this method due to the utilization of general consumption profiles on household consumption. These profiles encompass large amounts of consumption with dissimilar behavioral patterns to households, and in their creation, only the overall consumption statistics have been considered. In the *AreaAgg* case the behavioral patters have even been weighted into the profile. However, as subsection 2.1 explains, the general consumption is driven by parameters closely linked to the residential consumption. Although this effects are somewhat dampened in the general consumption profile, the use of these profiles were considered satisfactory.

Week 52 have been left out of the calculations, due to a fault in the profiles, further explained in section 6.3.

6.2 Socioeconomic benefit

The EMPS model provides results for the socioeconomic benefits generated in the simulations. These results are calculated as the average social economic benefit for the total system over all simulated inflow years. Here several parameters are included:

- Producer surplus
- Consumer surplus
- Revenues obtained from bottlenecks
- Reservoir income

The producer surplus describes the total revenues to all producers in the system, and the revenues of bottlenecks describes the revenues to the TSO. Reservoir income is a parameter set to account for the changes in reservoir levels when the model moves from one simulated inflow year to the next. (24). These values are all calculated as average values for the Norwegian system.

As results gathered directly from the model for the consumer surplus indicated faulty values, the consumer surplus presented in chapter 7 was calculated manually. Both firm demand and flexible load demand were used in the calculations, which were done in accordance with equation 6.3. The simulated firm demand was slightly different in each case, so a correction factor was utilized to account for these differences.

$$CS = \sum_{h=1}^{218400} (MWP_{Firm} - P_h) \times C_{Firm,h} + \sum_{h=1}^{218400} (MWP_{Flex.load} - P_h) \times C_{Flex.load,h} \tag{6.3}$$

CS	=	Consumer surplus [M€]
MWP_{Firm}	=	Marginal willingness to pay firm demand [€$/MWh$]
$MWP_{Flex.load}$	=	Marginal willingness to pay flex.load [€$/MWh$]
P_h	=	Power price in hour h [€$/MWh$]
$C_{Firm,h}$	=	Firm consumption hour h [MWh]
$C_{Flex.load,h}$	=	Firm consumption hour h [MWh]
h	=	hour of the 25 years of simulation

The marginal willingness to pay for firm and flexible load demand were sat to 375 €$/MWh$ and 500 €$/MWh$ respectively, representing the upper limits presented in section 5.1. Although there is some uncertainty in this simplified method, it produces comparable results when applied to each case. The main goal was to investigate the relations between the five cases, and as the same method is applied in each case, this goal is achieved.

Total social surplus was found by addition of the four parameters described in the beginning of this subsection.

6.3 Limitations and sources of errors

In the analysis preformed in Chapter 7, focus is in great parts directed to one area, Norgesyd, in addition to some overall effects to the Norwegian system. To study the effect of changed consumption profiles more closely, considering the geographical different profiles presented in 5.2, an analysis of differences in areas would have been interesting. Due to time limitations, only Norgesyd was regarded.

Additionally, one should keep in mind that changes have only been made in Norway. An isolated utilization of DR to Norway is improbable, although the change in consumption will happen locally. In the interconnected Nordic power system, the impacts from changes in one country will affect the others. Therefore, the effects from e.g. reduced consumption in Sweden will not be reflected in the results presented in this thesis.

Wet, Normal and Dry years

Through the simulation period, 25 different inflow years are processed. In addition to evaluating average values for the evaluation criteria mention in the introduction to this section, values specific to certain inflow years have also been considered. These years were chosen based on a combination of total annual inflow shown in appendix B and prices produced in *Historical*. The year 1990 was chosen to represent a wet year, 2004 a normal year and 2010 a dry year. As only one year was studied for each type, some caution must be taken when drawing conclusions in regards to the impact of inflow.

Week 52

Late in the adaptation process of the annual profiles, an error was discovered. The aforementioned neglecting of day 365 was not implemented in cases *Optflex* and *Separation*, resulting in one extra day in the summation of consumption in week 52. This week therefore contains a larger share of consumption than it should, which again leads to a much steeper increase in the annual consumption profiles for the last week of the year. This can be seen in figure 6.1, where the annual household profiles for all cases are depicted. Where the profiles for *Historical*, *Flat* and *AreaAgg* experience a dip in the last week of the year, a steep upward slope is shown for *OptFlex* and *Separation.* These cases encompass the same effect in the annual profiles of all remaining firm contracts.

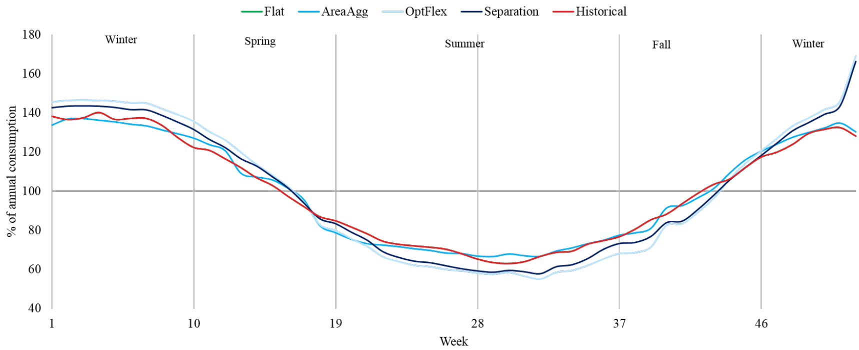

Figure 6.1: (Faulty) annual household profiles for all households, all cases.

An extra day of consumption through the week results in quite significant increase in the relative value of this specific week. For the household profile, the correct amount of consumption is 155.8 %, while the input profile is at 177.8 % for week 52, signifying a 22 % difference. As the annual profiles contains relative values, the increase in week 52 also leads to a slight decrease in the other weeks. When the household decrease of 22 % is distributed over the 51 remaining weeks, each week will experience a 0.43 % reduction in demand. This decrease is not considered noteworthy enough to affect the overall results, and is thus not corrected due to time limitations.

7 Results and discussion

This chapter present and discuss the results produced in the simulations of the five cases. The discussions will focus on how output is affected by the change in subdivision of firm demand and the demand profiles, rather than the implemented DR in its self. First the firm and total consumption will be investigated, followed by a close look at the simulated power prices. Furthermore, the economical incentives to the consumer are assessed, and the social surplus will be considered. The cross-border power exchange abroad will be evaluated, before a summarizing discussion is performed. Lastly, the results are compared to the findings of Tore Dyrendahl.

During the presentation and discussion of the results the focal point will be the relations between the five cases, rather than the actual values of different parameters. To investigate the impact of the different ways of modeling demand, it is the change in output that is of interest.

7.1 Consumption

In this section, a comparison of the differences in demand for all five cases is conducted. As no changes have been made to the industrial, flexible load consumption, only firm demand is evaluated in detail. However, as section 7.2 will elaborate, there is a difference in the number of occurrences of maximum prices for each case. A higher share of maximum price hours indicate a larger share of reduction in the industrial demand. Nevertheless, a closer study of the correlation between flexibility in industrial demand and the changes in firm demand will not be conducted.

In the *Historical* simulation, the average Norwegian firm demand through 25 inflow years is 88.8 TWh. The year 2010, which was a dry and cold year, produces the maximum annual firm demand through the simulation period, of 93 TWh, while the minimum annual consumption of 86 TWh is found in the wet and mild year of 2000. This difference of about 7 TWh support the importance of the temperature dependency in the data set. Figure 7.1 depicts the minimum and maximum consumption of all five cases. While minimum and maximum values occur in the same inflow years for *Historical*, *Flat* and *AreaAgg*, the two cases where a finer firm demand resolution have been introduced, *OptFlex* and *Separation*, move their min/max to other years. They do however follow the same pattern, and the new min/max years share similar attributes to 2000 and 2010.

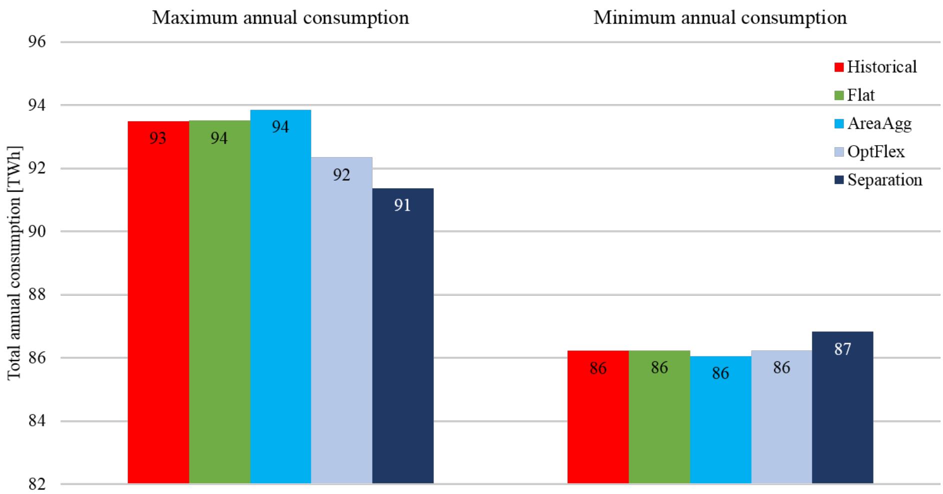

Figure 7.1: Maximum and minimum total annual consumption [TWh] through the simulation period

Separation shows the smallest difference between maximum and minimum annual firm consumption, due to the new temperature profile of *Households* consumption. When the non-temperature dependent *Hot Water* and *EV* consumption is extracted, the remaining residential consumption is left more sensitive to the variations of the different inflow years. However, the effect is canceled out by the 15 % (hot water) of the former general consumption that is now unaffected by these variations, leaving the total firm demand less temperature dependent and thus making the variations of inflow years less important.

Figure 7.2 depict a load duration curve for firm demand through the simulation period of 25 years, in addition to listing maximum and minimum hourly loads. An evening out of consumption can be seen for *Flat*, with reduced maximum load and increased minimum load.

Meanwhile, the opposite is shown for *OptFlex*, which has both the highest and lowest maximum and minimum load respectively, compared to the other four cases. Its duration curve also shows the most varying consumption through the simulation period. Both *AreaAgg* and *Separation* slightly reduces their maximum demand compared to *Historical*. At the same time, a reduction in minimum load can be seen for *AreaAgg*, while an increase is shown for *Separation*. This is due to the change in temperature dependency in *Separation*, which will be further explained through this section.

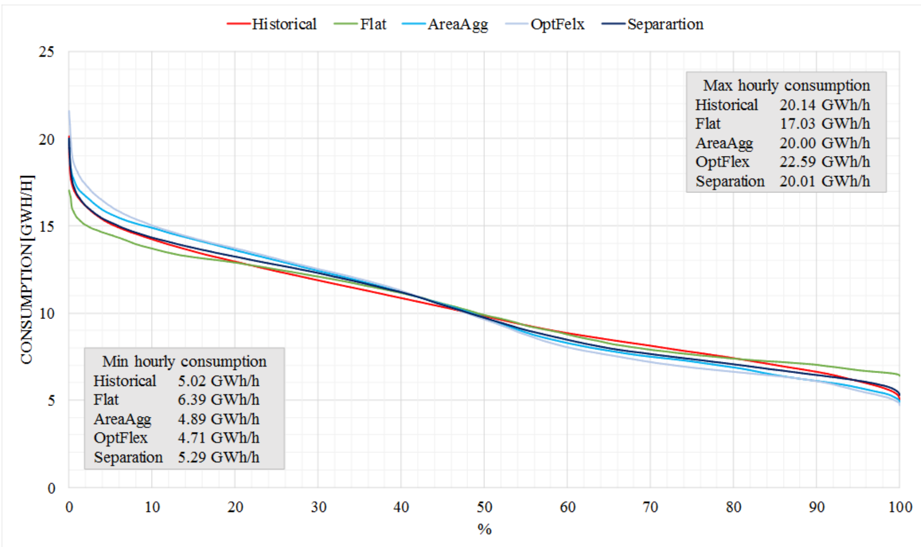

Figure 7.2: Hourly consumption through the simulation period,

Hourly variations in total consumption

Table 7.1 present the average percent change in hourly consumption for each case, compared to the hourly consumption from *Historical*. Here, both industrial and firm demand are included. This compares the Norwegian consumption quantity for each hour in the new cases, to the original hourly consumption simulated in *Historical*. An average percent reduction indicate more hours with reduced consumption, regardless of whether or not it happens in peak hours. While figure 7.2 depicts the overall differences in consumption for the five cases, the hourly, average percent change in consumption indicates how the correct, compared case hour matches the *Historical* hour. This way the hourly changes are highlighted.

Altogether, the cases with profiles from the Leopard model generate an average reduction in hourly demand, as seen in table 7.1. Meanwhile, the *Flat* weekly profiles result in a slight elevation of average hourly consumption. This increase compared to *Historical* can be explained by the price elasticity, as flatter consumption yields fewer high prices. The prices will be further discussed in section 7.2.

	Norway			
	Accumulated	Dry	Normal	Wet
Flat	0.09 %	0.10 %	0.09 %	0.09 %
AreaAgg	-1.90 %	-1.79 %	-1.93%	-1.97 %
OptFlex	-3.21 %	-5.01%	-3.87 %	-2.82 %
Separation	-1.21 %	-4.01 %	-2.04 %	-0.96 %

Table 7.1: Average percent change in hourly consumption compared to *Historical* values

While the change in *Flat* consumption is easily explained, the decrease caused by the Leopard model is less evident. This is related to both peak shifting, further explained in the next paragraph, and the temperature dependency. Figure 6.1 shows the new annual Households profiles for all cases, *Flat* is equal to *Historical*. The profiles of *OptFlex* and *Separation* are more seasonal than the other profiles, with more consumption distributed to the winter, and less to the summer as the profiles are relative. When the weeks are temperature corrected, consumption is "shifted" between the different inflow years. As deduced above, the accumulated sum of consumption through 25 years remains the same. The temperature correction is however amplified for consumption with more volatile profiles, shifting the consumption more violently between inflow years. The impact of temperature on the hourly reductions is supported by the changes seen *Separation*, were hot water is extracted and the accumulated percent reduction is smaller.

Det er denne forklaringen jeg er litt usikker på

Furthermore, the Leopard model aims to even out the consumption within the week, to reduce peak hours and thus strain to the grid. The evening out leads to great reductions compared to *Historical* in peak hours, while smaller differences are seen in the increased non-peak hours. This totals in large average reductions when comparing the different cases. As the service sector and primary sector is similar in all cases, it is assumed that the effects shown in weekly distribution are derived from changes in residential demand.

Weekly variations in consumption

The new weekly load profiles result in different distribution of hourly firm consumption through the week. Only one area is considered in the further evaluation of weekly effects in firm consumption, namely Norgesyd. This region was chosen based on the price analysis presented in the next section. The different effects will be similar in all Norwegian areas where the firm consumption have been altered, making the analysis of one area valid. Norgesyd is classified as a coastal area with a big share of service activity.

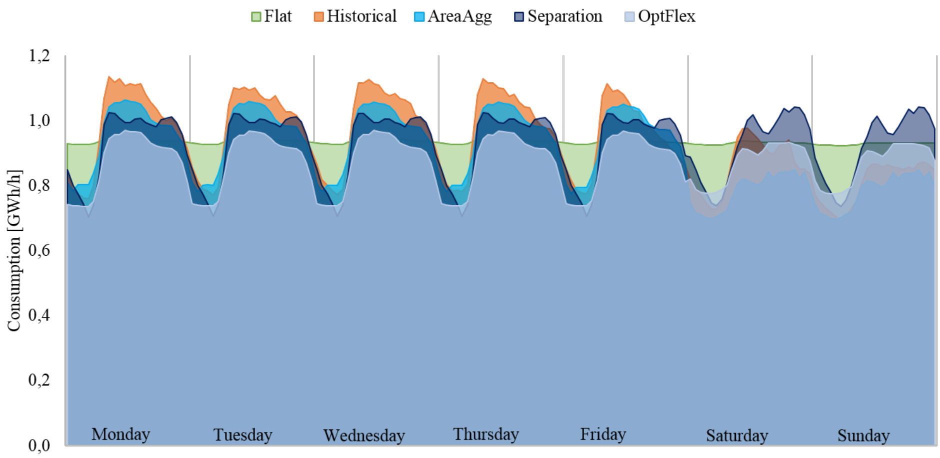

Figure 7.3: Firm consumption in a summer week (25) for a dry year in Norgesyd

Figure 7.3 and 7.4 show weekly variations of firm consumption in a dry year. The former depicts a summer week, where peak reduction is seen in all cases, naturally due to the implementation of flexibility. The daily distribution of demand is similar in weekdays and weekends for cases with Leopard profiles, as a result of the how the model constructs its profiles, explained in chapter 4.

The consumption of *AreaAgg* varies more during the weekdays, and is significantly reduced in the weekend, with peaks both shifted and reduced compared to *Historical*. Additionally, the consumption is slightly higher during the night hours, reflecting the integrated optimization of EV and hot water consumption. *OptFlex* show a more even consumption through the week, with higher and less varying consumption during the weekend. Meanwhile, the weekday consumption retains the shape of *AreaAgg*. *Separation* shows a more fluctuating consumption, with large reductions during the night. This is caused by the optimization of the flexible demand in *Hot Water* and *EV*. The level of consumption is retained through the weekend. Historically, consumption is reduced and evened out during the weekend, as the depicted *Historical* demand suggest. Therefore, the high weekend consumption in *OptFlex* and *Separation* can be seen as quite unrealistic.

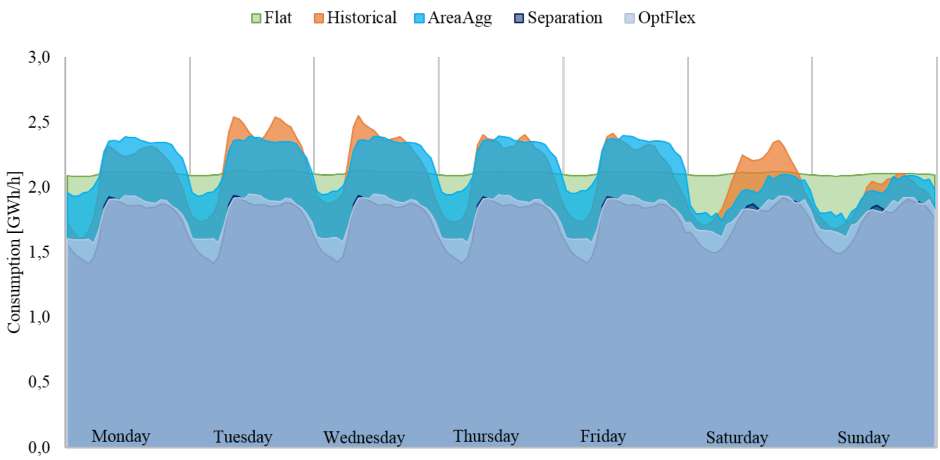

Figure 7.4: Firm consumption in a winter week (49) for a dry year in Norgesyd

Compared to the summer week, the winter week in figure 7.4 show similar weekly distribution for all cases except *Historical*, although the consumption level has increased. This indicates that the seasonal variations do not much affect the shape of daily distribution, not even in the aggregated profiles of *AreaAgg*, where the aggregated profiles from the Leopard model are utilized.

If the summer weeks of a dry year (displayed in figure 7.3) and a wet year (figure 7.5) is compared, a greater difference is evident for *Separation*. Here, the effect of the non-temperature dependent *Hot water* and *EV* consumption is more noticeable, when compared to the profiles presented in figures 5.3. This points out the influence of the temperature dependency on the weekly distribution when contracts with different dependencies are assigned to an area. In the wet and mild year, the temperature dependent consumption is decreased so profoundly that the rigid peaks from EV and Hot Water become defining in some hours. This is interesting, as they only make out about 20.5 % of input residential consumption. The effect is also noticeable in winter weeks.

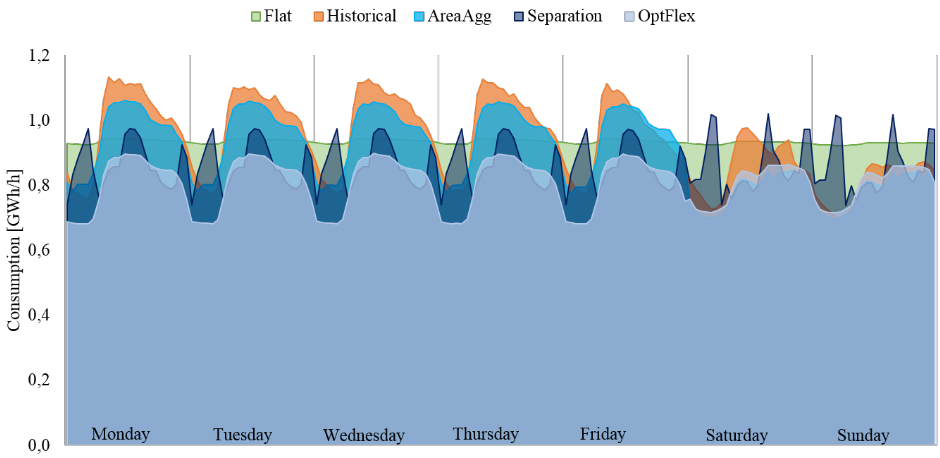

Figure 7.5: Firm consumption in a summer week (25) for a wet year in Norgesyd

The distribution of demand in *AreaAgg*, *OptFlex* and *Separation* is as mentioned a result of the optimization to even out residential consumption. However, a flattening of consumption might not always be the goal when utilizing demand response. In a power system with higher penetration of intermittent production, it can be desirable to reduce consumption in hours of poor production and increase it again whenever the wind is blowing strong or the sun is shining. This valley filling of consumption is of course not desirable from a grid perspective, if the power is distributed through the grid and not produced and used locally. Nevertheless, the profiles provided by the Leopard model do not enable this usage of flexibility. Simultaneously, the EMPS model will have difficulty to render this usage through annual and weekly profiles alone, as mentioned in subsection 3.3.

7.2 Prices

The prices regarded in this section are collected from the EMPS area Norgesyd, which coincides with the Nord Pool area NO2 considered by Tore Dyrendahl. Despite the smaller geographical extent of Norgesyd compared to NO2, suggesting a more limited inclusion of the southern Norwegian power system, the interesting aspects of this area are accounted for. It is interconnected abroad to Germany, Netherlands and Western Denmark, although the cable to the United Kingdom is not directly connected to Norgesyd. However, it is connected to the neighbouring area Vestsyd, which in turn is modelled with a transmission line of infinite capacity to Norgesyd. This modeling of transmission capacity is also applied to Telemark and SKL, allowing a flow between the areas free of bottlenecks. Subsequently, the wast reservoir and hydro power capacity of NO2 are reflected in the the Norgesyd prices.

Altogether, these effects make the Norgesyd prices equal to the NO2 prices, although a direct comparison is not preformed in this thesis.

The case duration curves for all simulated prices through the 25 inflow years in Norgesyd are shown in figure 7.6.

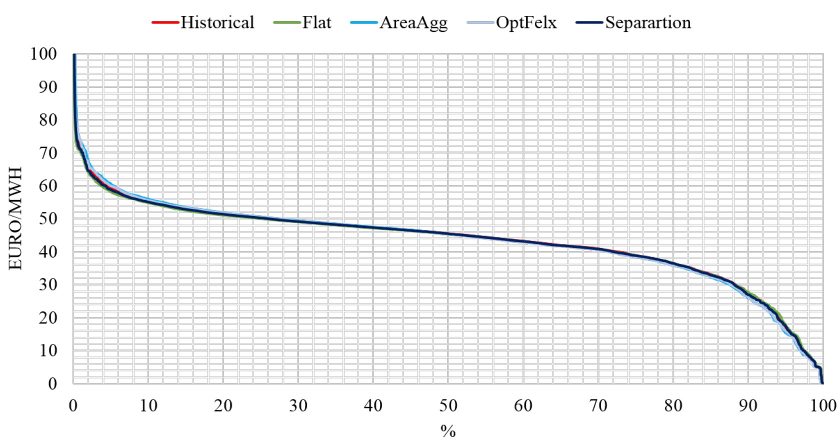

Figure 7.6: Duration curve of all prices through the simulation period (25 years), hourly prices all cases [Euro/MWh]

Historical upholds slightly higher prices than all remaining cases in the lower 50 % price field, with the exception of *Flat*, which is the most expensive in the lower 10 %. A more prominent difference can be seen in the top 10% price field, displayed in the zoomed in figure 7.7. Here *AreaAgg* contributes with the highest prices, while *Flat* has noteworthy lower prices in this price field. Both duration curves are zoomed in to better see the variations, as a maximum price of 375 $€/MWh$ is reached in all cases. The average maximum prices are presented in table 7.2, showing a maximum price in *Flat* at about 10$€/MWh$ less than the other four cases.

	Historical	Flat	AreaAgg	OptFlex	Separation
Max average price	82.2	70.6	83.2	82.1	79.2

Table 7.2: Average maximum prices for all cases[$€/MWh$]

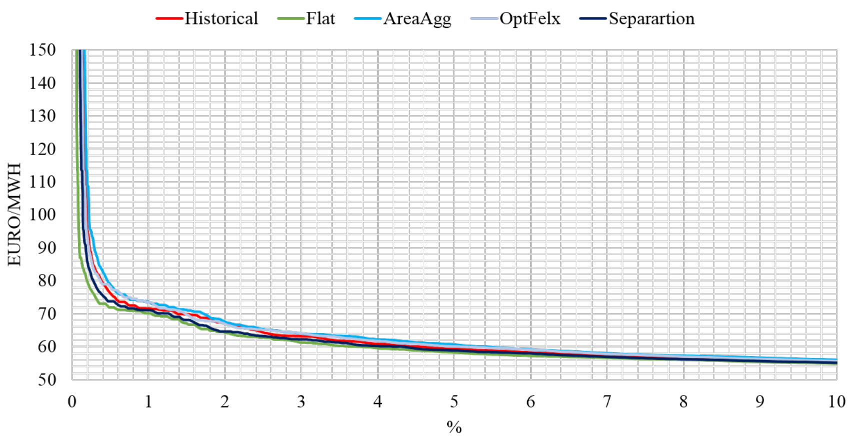

Figure 7.7: The top 10 % of simulated power prices for all cases [Euro/MWh], zoomed from figure 7.6

Altogether, *Flat* produces more stable prices, with smaller fluctuations through the year. Meanwhile, *AreaAgg* and *OptFlex* experience slightly more volatile prices than *Historical*, with lower and higher price levels respectively in the bottom and top price fields. *Separation* is the only case which experiences lower average prices than *Historical* in both the bottom and top, although it follows the same pattern in the middle 50% of the hours. *Flat*'s evening out of prices was to be expected, as flat firm consumption through the week typically will lower the prices in traditional peak hours and up them in common low load hours.

The above difference in price levels can also be seen in the weekly prices depicted in figures 7.8 - 7.12. These graphs are zoomed in to a maximum price of 120€/MWh, and the full scale graphs for all cases can be found in appendix C. Additionally, week 52 have been omitted due to the error in the annual profiles of *OptFlex* and *Separation* communicated in subsection 6.3.

As all cases are provided with the same modeling of production and inflow, the shape of the curves in all cases are quite similar, following the annual variations in inflow. The average prices exceeds the median values in the winter weeks, indicating large differences in the higher prices in these periods. Hours of very high prices elevate the average price level. Similarly, the opposite effect can be seen in the summer months, where there is a higher concentration of low price hours.

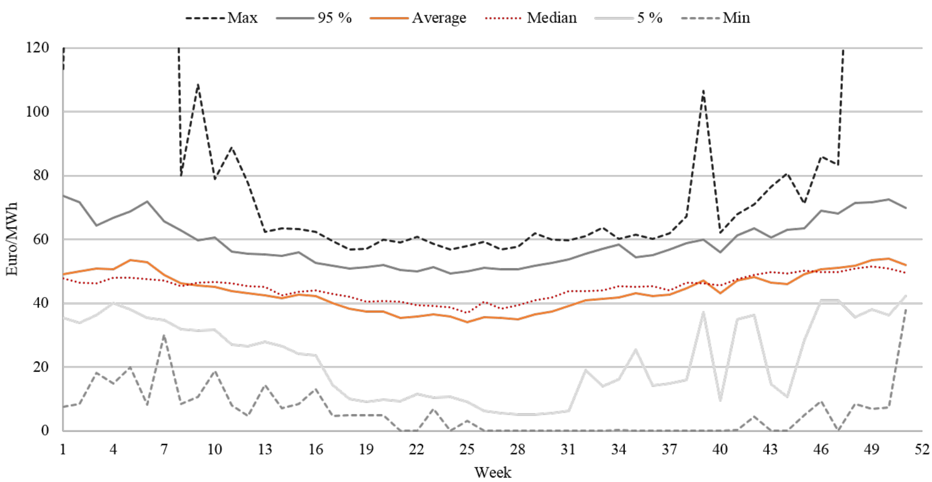

Figure 7.8: Weekly prices Norgesyd, *Historical* [€/MWh]

The largest case variations can be found in the extremities of maximum and minimum prices. While *Flat* shows a strong reduction in weeks which experience extreme prices through the simulation period, *AreaAgg* retains a level slightly higher than *Historical*. A reduction in weeks with peak price hours is also found in *OptFlex* and *Separation*, although not as great as for *Flat*. In the winter weeks 5, 6, 7 and 49 all cases experience hours where the prices reach the practical maximum price in the model of 375 €/MWh, accounted for in subsection 5.1. This maximum price is never exceeded, indicating a high enough share of industrial consumption to accommodate any necessary reductions in total demand. In hours of needed flexible demand reduction, the disconnection price will determine the power price.

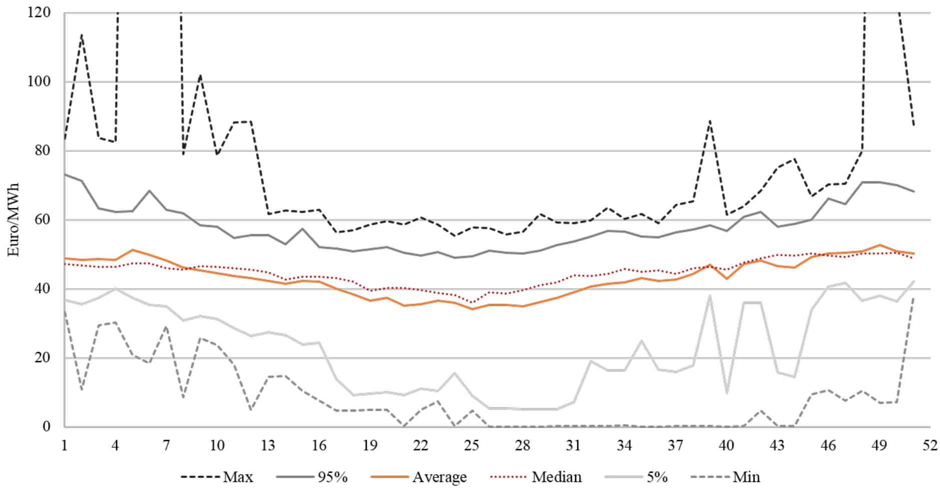

Figure 7.9: Weekly prices Norgesyd, *Flat*[€/MWh]

When regarding the minimum prices, all cases have weeks where hourly prices below 0.6 €/MWh occur. In some of these hours, it is the continental power prices which determine the area price of Norgesyd, due to import. Here, the pre-simulated price series in Germany reflect the aforementioned effect of wind and solar power, pushing the Norwegian prices down. Another price minimizing effect appears in years with very high weekly inflow, where the decrease in prices is a result of avoiding spillage in the reservoirs. Nevertheless, both inflow and the abroad price series are identical in all cases, suggesting an effect drawn from the change in consumption.

Through the simulation period, hours with minimum prices below 0.6 €/MWh occur in 22 of the 52 annual weeks in *Historical*, whereas *Flat* has occurrences in 20 weeks. Again, a reduction of the extremities is shown in *Flat*. A reduction in weeks with minimum prices is also found in *Separation*, with a 20 weeks occurrence. *OptFlex* experiences a similar number of weeks as *Historical*, while *AreaAgg* is the only case with an augmented count of 24 weeks.

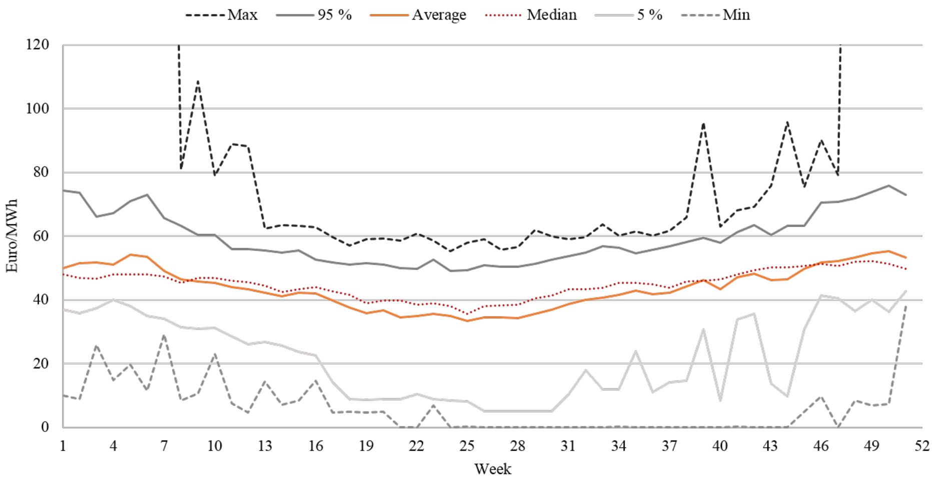

Figure 7.10: Weekly prices Norgesyd, *AreaAgg*[€/MWh]

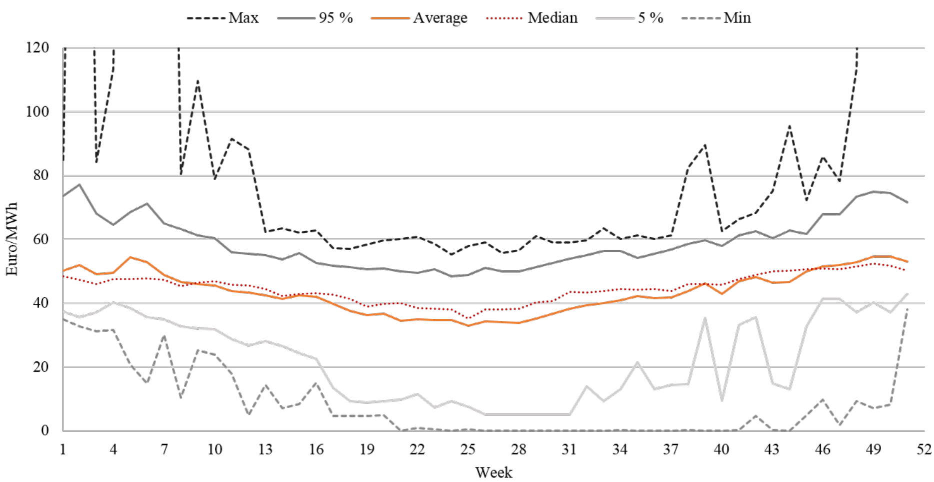

Figure 7.11: Weekly prices Norgesyd, *OptFlex*[€/MWh]

For the 5-percentile, *Flat*'s inclination towards less volatile prices is again reflected, as its low prices are slightly above those of *Historical*. Opposite, *AreaAgg*'s low prices are slightly below *Historical*, with the exception of the winter weeks. This support its tendency towards more volatile prices through the year. *OptFlex* and *Separation* experience an increase during the winter weeks and a reduction in the summer, the latter a little more prominent in *OptFlex* for weeks 30 to 34.

The large difference between the 95-percentile and the maximum prices during the winter supports the aforementioned effect of average prices surpassing the median as a result of a few very high prices. However, patterns between the cases similar to the maximum price patterns can be seen for the 95 percentile. During the late fall and winter weeks, *AreaAgg* exceed *Historical*. Meanwhile, *Flat* displays reduced high prices through most of the year. *OptFlex* high prices fluctuate around *Historical* prices through the year, and plainly surpass them in the coldest winter weeks 1 to 3, and 48 to 51. Lastly, *Separation* experience a similar price level as *Historical*, with the exception of the winter weeks where a slight reduction is shown.

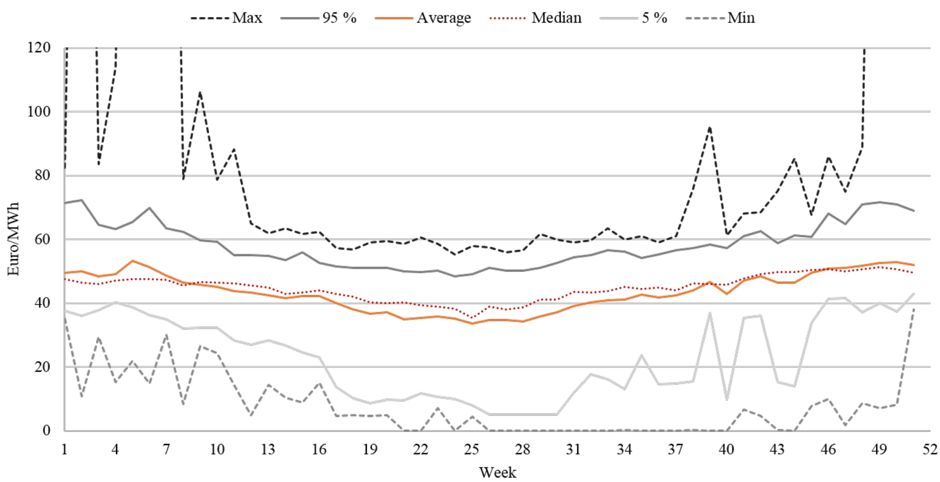

Figure 7.12: Weekly prices Norgesyd, *Separation*[$€/MWh$]

The above review is summarized in table 7.3, where the percent change in average prices from *Historical* average prices for each case in Norgesyd is displayed.

	Norgesyd			
	Middle	Dry	Normal	Wet
Flat	-1.06 %	0.19 %	-0.40 %	-0.19%
AreaAgg	-0.07 %	0.18 %	-0.14 %	-1.13 %
OptFlex	-0.55 %	-0.18 %	-0.06 %	-2.30 %
Separation	-0.67 %	-1.36 %	13.96 %	-0.29 %

Table 7.3: Average percent change compared to *Historical* in prices per year Norgesyd

Middle indicates the average prices of each hour for the 25 inflow years, and a price reduction is obtained in all cases. Naturally, *Flat* has the largest reduction due to the drop in maximum prices. The fluctuating prices in *AreaAgg* amount to the smallest average price reduction. *OptFlex* and *Separation* show similar average price reductions. These patterns of the Middle price percent change are not consistent with the changes seen in the different types of inflow years. In a dry year, *Separation* is the best outcome, while *Flat* and *AreaAgg* is on the other end of the scale with no reduction. A change is again seen in the Normal year, where *Separation* prices increase noteworthy. Moreover, the largest price reduction is seen in a wet year, with an over 2 % reduction for *OptFlex*. The effects of different inflow years will be further discussed in the following section.

Wet, Dry and Normal years

The seasonal variations in power prices in the Norwegian power system are prominent, due to its high share of hydro power production. As mentioned in subsection 7.1 the case variations are amplified in the different inflow years. Figure 7.13 and 7.14 show hourly prices through three different types of years for *OptFlex* and *Separation* respectively. Similar figures for the three remaining cases can be found in appendix C. All graphs are zoomed in to a maximum price of 85 €$/MWh$, to enhance the majority effects.

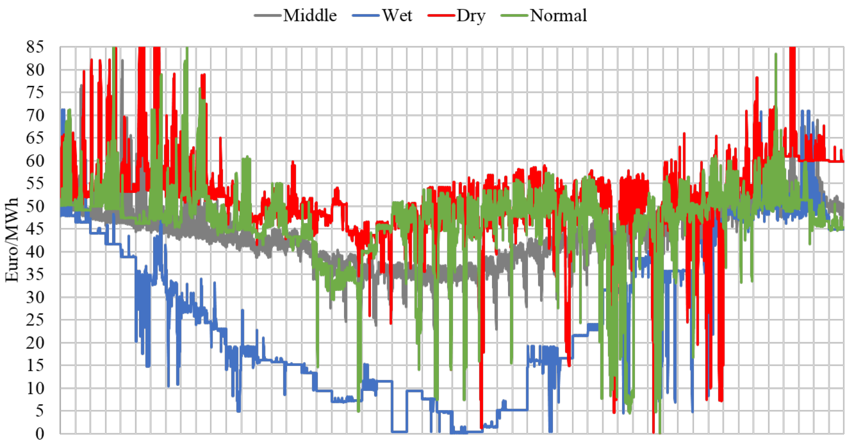

Figure 7.13: Hourly *OptFlex* prices through wet, dry and normal year, including middle prices

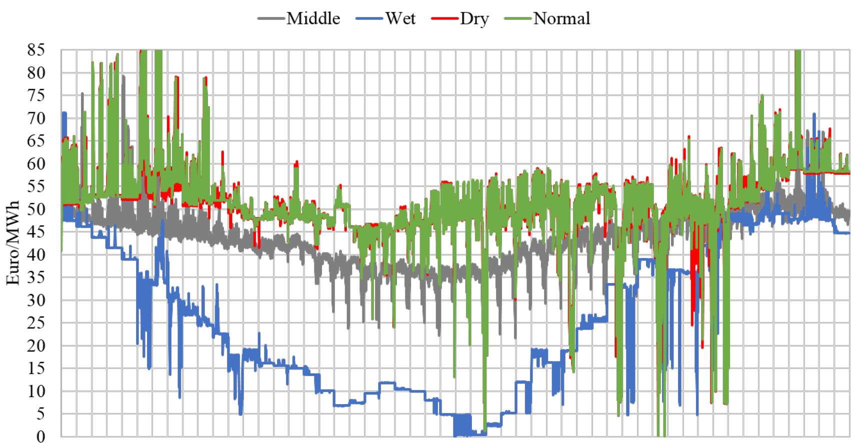

Figure 7.14: Hourly *Separation* prices through wet, dry and normal year, including middle prices

The increase of seasonal variations in *OptFlex*'s new annual household profile, are clearly reflected in the power prices specific to different inflow years. In wet years, the summer prices are reduced, due to the decreased consumption and the effects explained in the previous subsection. A reduction is also present in the winter weeks. Opposite, a noticeable increase in winter prices can be seen for dry years, while a slight decrease is seen for some hours in the summer. Meanwhile, the more extreme effects are evened out in the middle prices, with a slightly stronger influence from the decrease in wet years.

When regarding the prices from *Separation*, which also have a seasonal annual profile, the influence from the temperature dependency seem to be evident again. The effects seen in *OptFlex* is damped, as less firm consumption is temperature dependent. However, in a normal year, a great increase in prices is shown, probably due to the increase in consumption due to less temperature sensitivity.

Weekly price variations

Section 7.2 briefly discuss the effect of import and export on the Norwegian power prices. To complement this discussion, the hourly prices through a winter week and a summer week have been examined. As deduced in the previous section, the type of inflow year is of importance, and thus the weeks are considered for both a dry and a wet year. Figures 7.15 through 7.18 depict both case specific prices and German prices, in addition to firm consumption for all cases. The consumption levels are presented to investigate the correlation of demand and price through the week.

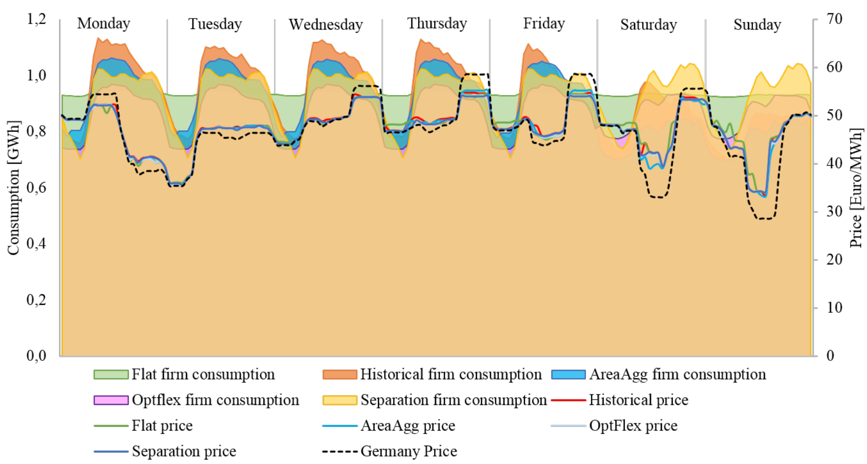

Figure 7.15: Prices and consumption for summer week 25 in a dry year

In figure 7.15 and 7.16 week 25 and week 49 in a dry year are depicted respectively. The Norwegian power price follow the same pattern as the German power price in both weeks, for all cases, although with slightly less volatile levels. Additionally, it can be seen that there are only slight variations between the cases in the summer week. In week 49, non of the case prices reach the German level, as the cut off from industrial demand limits the Norgesyd price to 375 $€/MWh$. Meanwhile, *Separation* show a lower maximum price in week 49, most likely due to its differing temperature dependency explained in section 7.1.

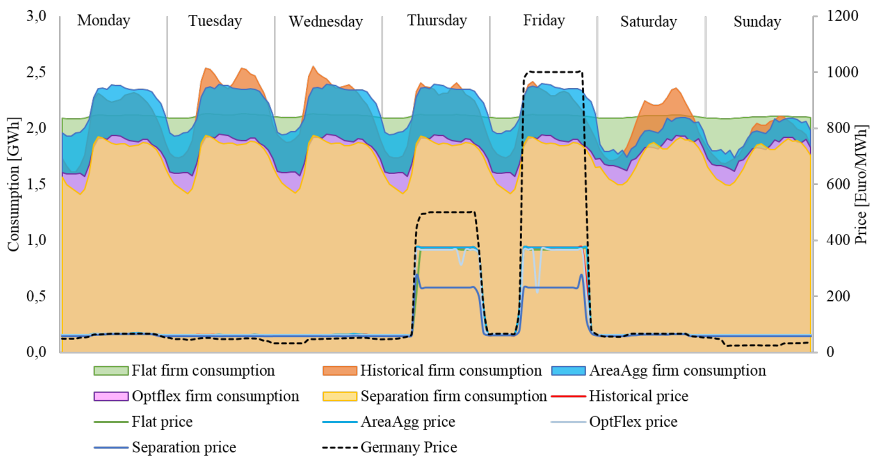

Figure 7.16: Prices and consumption for winter week 49 in a dry year

A greater variation between the cases can be seen in wet years, as figure 7.17 and 7.18 show. During the summer week, the price levels of the Leopard cases are consistently lower than *Flat* and *Historical*. This is an effect of the lower summer consumption level in these cases. While the Norwegian prices seem to be affected by the large dips in the German price, their main driver is not the continental prices overall. The impact of these prices are dampen and the prices are determined by the marginal costs of hydro power.

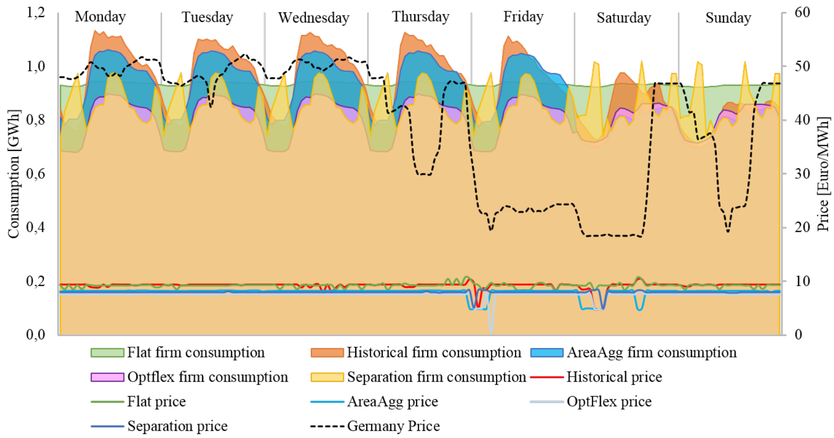

Figure 7.17: Prices and consumption for summer week 25 in a wet year

During the winter, some influence can be seen. In the period, *OptFlex* and *AreaAgg* are affected the most by the price peaks in German prices.

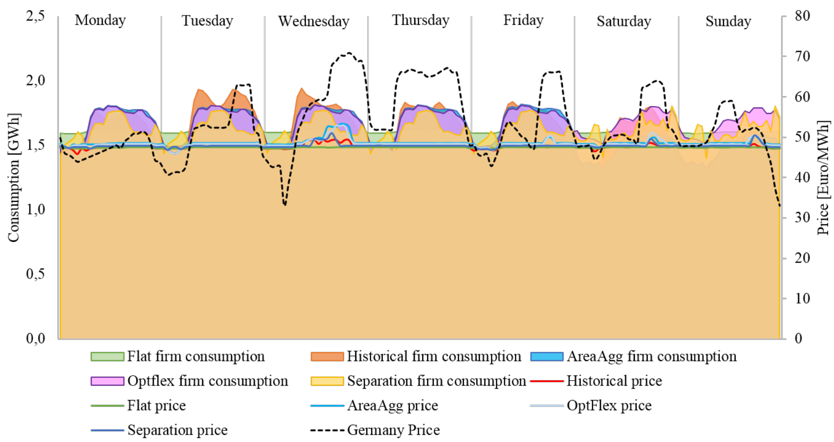

Figure 7.18: Prices and consumption for winter week 49 in a wet year

Altogether, the Leopard cases where demand response have been implemented, seem to follow the continental power price slightly more closely than *Historical* and *Flat*.

7.3 Incentives for the consumer

The key participant in demand response is of course the consumer, so an evaluation of how DR can prove beneficial to the consuming customer is necessary. As explained in section 6.1, the economical incentives for the consumer have been deduced by comparing their electricity bill before and after demand reduction. The two mentioned scenarios considered are as follows:

1. Case consumption and *Historical* prices
2. Case consumption and case specific prices

The case consumption refers to the total consumption of an average Norwegian household, distributed to hourly values with the generated case specific profiles. An average Norwegian household consumes the aforementioned amount of 16000 kWh per year, and in scenario 1 this accumulates the electricity bills depicted in figure 7.19. Here, NorgeSyd prices have been utilized. On average, *Historical* is marginally more expensive compared to *Flat* and *Separation*. The latter is the more expensive in mild and wet years. *AreaAgg* and *Optflex* show reductions in all types of inflow years.

Figure 7.19: Annual electricity bill of an average Norwegian household [€]]

As *Historical* prices are utilized in the calculations shown in figure 7.19, it is evident that the difference in cost of consumption is caused by the hourly load shifting through the week. The same amount of flexibility has been assigned in the three Leopard cases, yet different effects are produced in the output profiles. *AreaAgg* presents the greatest shifts, closely followed by *OptFlex*. For *Separation*, the marginal reduction indicates similar consumption patterns to *Historical*. A surprising result is seen in *Flat*, as only very small reductions are produced by the evening out of consumption. This indicates that the increase in consumption in low-load periods have a greater negative effect on costs than the positive effect drawn from a decrease in peak load, and thus high price, hours.

Even though a decrease in annual costs is good, in regards to a household customer, the magnitude of these reductions are of importance. Unless automated systems are installed, large amounts of savings are necessary to compensate for the inconvenience a manual shift in demand imposes. Seeing that the restrictions introduced in the optimization attend to the physical discomfort of reduced consumption, this inconvenience refers to time spent following the communicated price signals and the efforts needed to switch on and off appliances.

Figure 7.20 and 7.21 depict the annual savings to the consumer, compared to *Historical*. While the red columns refers to scenario 1 where *Historical* prices are utilized, the green and blue columns use prices and consumption for the specific case. The red columns represent the forward consumer, which exercise DR before the rest, while the other columns show the benefits after a collective change in consumption have taken place. The latter thus display the long term effects, depicting the savings, should the consumption shift be maintained.

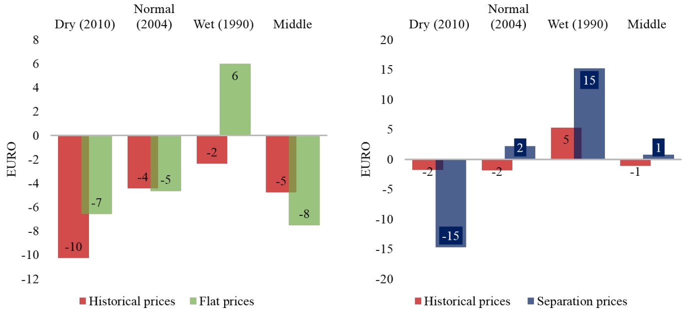

Figure 7.20: Annual savings to the average Norwegian household consumer [€], *Flat* and *Separation*

In figure 7.20 the least beneficial cases of *Flat* and *Separation* can be seen. *Flat* shows reductions in all types of inflow years, with a max reduction of 10 €in dry years and an average reduction of 5 €for scenario 1. Meanwhile, in *Separation* smaller reductions are seen, one can even see an increase in cost for wet years. For scenario 2, this cost increase is also present in *Flat*, although a small average cost reduction is maintained. The increase in average reduction compared to scenario 1 can be explained by the smaller price differences presented in section 7.2. In both *Separation* and *Flat* the magnitude of annual savings are too low to trigger an average consumer to exercise demand response, so automated systems would be necessary. In such cases, the cost of installation would need to be considered. This is however outside of the scope in this thesis and will not be further discussed.

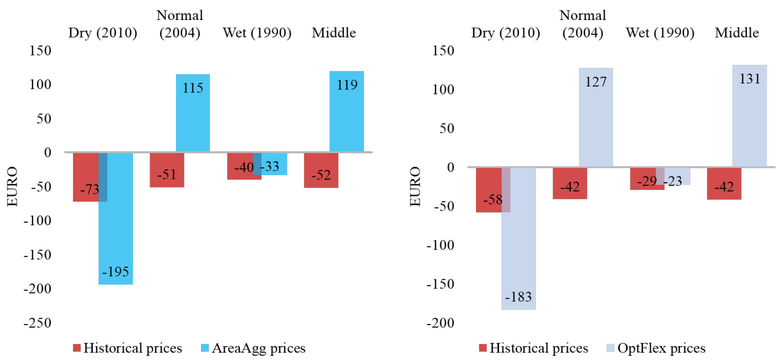

Figure 7.21: Annual savings to the average Norwegian household consumer [€], *AreaAgg* and *OptFlex*

A larger change to the consumer can be seen in *AreaAgg* and *OptFlex*. In scenario 1 the average annual savings amount to 52 €and 42 €respectively. However, this might not be sufficient to activate the affluent Norwegian consumer. Meanwhile, the amounts displayed in dry years of scenario 2 might be large enough. Here the decrease in power price generates savings of 195 €and 183 €for *AreaAgg* and *Separation* respectively. These saving could potentially work as a boost for further reduction in the year following a dry year. Unfortunately, the average power prices actually indicates large losses to the consumer, even though they are reduced compared to *Historical* as seen in table 7.3. Therefore, in these cases, demand response must be facilitated by the utilities rather than the consumer.

The profitability to the consumer is present in all cases for scenario 1, although it differs in magnitude. A forward consumer could gain savings by altering their demand when *Historical* prices are utilized. The long term effects are less profitable however, with explicit losses shown in both *AreaAgg* and *OptFlex*.

The discouraging results for the long term effect outlined in this section are not necessarily completely accurate. The demand response implemented in this thesis aims to flatten out the consumption and in their creation, prices have not been considered. Demand response facilitated through price signals will thus not follow the exact patterns of the household profiles used in this analysis. Additionally, the *Historical* profiles used for comparison are created for general consumption, which has a flatter profile than household consumption due to contributions from other sectors than the residential sector. To gain more accurate results, a correct historical profile and a match of high price hours and reductions could have been used. However, due to time and data limitations, this simplified method was applied.

One should also note that as the spot price is directly utilized in the calculations, the value added tax (VAT) of 25 % is not included. This will reinforce the aforementioned effects. Additionally, it is assumed that the energy tariff scheme used today is maintained. In accordance with current pilot projects conducted for demand response, further discussed in the preliminary work for this thesis (15), other tariff schemes might be utilized in the future. This might produce other results.

7.4 Social Surplus

Flexibility and demand response will of course not exclusively affect the parts of the power system mentioned above. Unfortunately, deeper analyses of the total system have been restricted by scope and time limitations. However, to gain an understanding of the total picture, the social economic benefit has been evaluated. Figure 7.22 depicts the difference in social economic benefit of all cases compared to *Historical*. These values have been deduced in accordance with the process described in section 6.2.

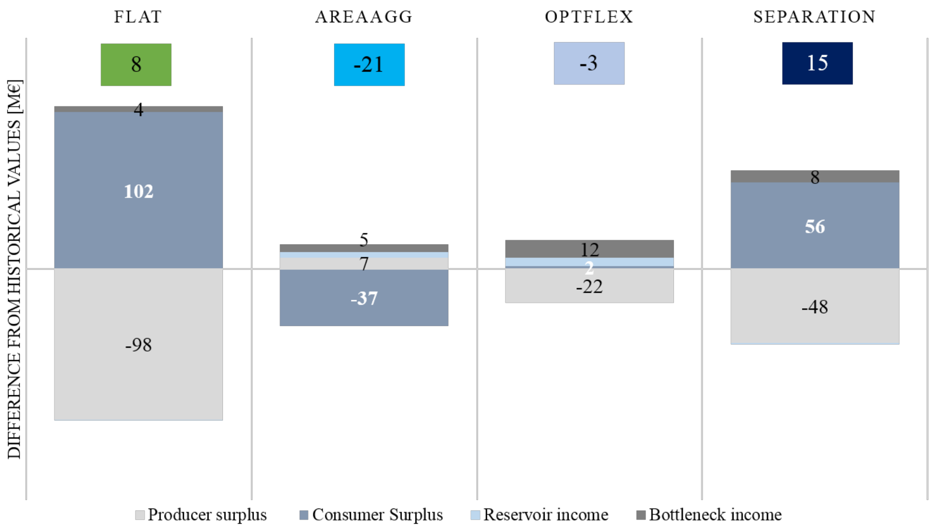

Figure 7.22: The difference of socioeconomic benefits for each case compared to *Historical* [M€]

With the exception of *AreaAgg*, all cases present a loss to producers when introducing demand response. With the reduction of power prices accounted for in section 7.2, this is not surprising. Lower power prices reduce the difference between marginal values of production and power prices, resulting in a reduced surplus. Opposite, in *AreaAgg* there is a small benefit to the producer of 7 $M€$, a result that is surprising considering the overall reduction in power prices compared to *Historical* for this case. However, if average prices are increased in hours of high production and decreased in hours of low production, hydropower producers might move their production to high price hours. This will result in a higher producer surplus, even if the power prices overall are decreased, and this effect may explain the positive outcome for producers in *AreaAgg*.

The consumer surplus is greatest in *Flat*, indicating that the evened out prices in this case yield great benefits to the consumers. This do not, however, compliment the findings in 7.3, where a larger reduction in cost was found when *Falt* prices were utilized. Meanwhile, an explanation could be found in the decreased amount of power intensive industry loads shutting down due to lower maximum prices. As *OptFlex* experience the largest hourly reductions in demand, only a very small consumer surplus is obtained. Of the Leopard cases, *Separation* yields the greatest consumer surplus, of 56 M€, indicating a match in price and consumption reduction. This is also the Leopard case that experiences the largest reduction in average maximum price. Opposite, *AreaAgg* has the highest average maximum prices, which in turn might explain the surprising negative consumer surplus.

While both producer and consumer surplus yield different indications in each case, the revenues collected from bottlenecks are positive for all four cases. This indicates greater area variations in power prices, resulting in a higher amount of bottlenecks and thus greater revenues to the transmission system operator.

In figure 7.22, total social surplus is depicted in the colored boxes beneath the name of each case. *Flat* and *Separation* produce positive results, of 8 Me and 15 Me respectively, indicating a total benefit to society when utilizing DR. Meanwhile, *AreaAgg* and *OptFlex* result in losses to society, both as an effect of the consumer surplus.

7.5 Cross-border power exchange

Average total Norwegian cross-border exchange abroad is displayed in table 7.4. An increase in export is seen in each case compared to *Historical*, with the exception of *AreaAgg*. However, the decrease in import in *AreaAgg* indicates a smaller share of net exchange abroad. The greatest change is seen in *OptFlex*, with an increased export of about 0.36 $TWh/year$. *Separation* also induce a higher share of export. Presumably, this is due the reduced consumption, explained in 7.1.

Case	Total export	Total import	Net export
Historical	**32.38**	24.62	7.76
Flat	**32.76**	24.85	7.91
AreaAgg	**32.33**	24.56	7.77
OptFlex	**32.74**	24.54	8.20
Separation	**32.95**	24.78	8.17

Table 7.4: Average total Norwegian cross-border exchange [TWh/year]

Tables 7.5 and 7.6 show the share of hours maximum cross-border export and import in Norgesyd respectively. These values are derived from the international cables. Compared to *Historical*, all cases show an increase in hours of maximum export. This is due to the reductions in hourly consumption, as a result of demand response. In these hours, it is the Norwegian hydro power which determines the power price in Norgesyd. The same is true for hours of maximum import.

	Norgesyd			
	Accumulated	Dry	Normal	Wet
Historical	13.4%	1.7%	3.0%	24.2 %
Flat	13.6 %	2.3 %	3.4 %	24.2 %
AreaAgg	13.6 %	1.7 %	2.0 %	24.5 %
OptFlex	14.1 %	2.4 %	3.2 %	24.6 %
Separation	13.8 %	1.9 %	2.6 %	24.4 %

Table 7.5: Share of hours with maximum export [%]

As table 7.6 presents, a reduction in hours with maximum import is seen in each of the Leopard cases compared to *Historical*. This compliment the increase in low power prices, as it indicates more hours with import in low-price periods.

	Norgesyd			
	Accumulated	Dry	Normal	Wet
Historical	1.4 %	1.8 %	4.6 %	0%
Flat	1.5 %	2.6 %	5.0 %	0 %
AreaAgg	1.2 %	1.4 %	4.3 %	0 %
OptFlex	1.2 %	1.8 %	4.2 %	0 %
Separation	1.3 %	1.7 %	4.5 %	0 %

Table 7.6: Share of hours with maximum import [%]

7.6 The impact of changing consumption profiles

The implementation of demand response has produced clear differences in each case. While *Flat* yielded the expected flat prices and thus increased and reduced consumer and producer surplus respectively, it was interesting to see the small average increase in hourly consumption. As a consequence, the expectation of a large decrease in cost to consumers was not met.

In the cases with new Leopard profiles, effects differed due to the difference in implemented temperature dependency. While *AreaAgg* and *OptFlex* show similar patterns, *Separation* stand out. Both *AreaAgg* and *OptFlex* experienced a more volatile consumption, and thus more volatile prices. Meanwhile, *Separation* produced a more stable consumption than *Historical*, which in turn resulted in the largest reduction of average maximum prices in the three cases. The seasonal shift of consumption seen in *AreaAgg* and *OptFlex* would be unfortunate for the power system, as the peak consumption might require higher design capacity of transmission lines. Only the latter case presented a higher consumption than *Historical*, indicating that the aggregation of demand profiles in *AreaAgg* yielded more even consumption.

AreaAgg, *OptFlex* and *Separation* all showed an inclination to follow the continental power price more closely during the week, complimenting the change in import and export seen in section 7.5. Due to the reduction in consumption, a decrease in hours of maximum import is seen. Meanwhile, the increase in hours of maximum export indicates more hours with hydropower determining the Norwegian power price.

These two effects result in an overall decrease in prices.

As mentioned, both methods used to calculate the profitability to the consumer and the social surplus respectively, contain sources of error. However, if the results presented in this chapter are assumed correct, *OptFlex* and *AreaAgg* yield surprising and discouraging results. While a socioeconomic benefit was expected, it was not produced. Neither was an average cost reduction produced for the consumers. Altogether, this indicates that demand response should not be encouraged, at least with this modeling from the Leopard model. Unless the TSO perspective is considered, where the increase in bottleneck income is favorable. Meanwhile, *Separation* show a positive benefit to society and a marginal increase in costs for consumers, indicating benefits from implementation of DR. These differences emphasize the importance of the sub-categorization and the change in temperature dependency.

The calculation of incentives to the consumer also highlights an important short-coming in usage of the flexibility optimization from the Leopard model to model DR. As the aim is to flatten out consumption, the "price-triggered" demand response is not accounted for. Consequently, no lasting savings for the consumer is produced, as the same hours will be reduced each year, and thus prices will be reduced in these hours. The optimization of flexible demand in the Leopard model should therefore be regarded as a tool seen from the utility perspective, rather than a customer responding to price signals.

7.7 Comparison to findings from Tore Dyrendahl

The large implementation of ZEB's in Norway produced price structures similar to the price changes seen in this thesis. This is naturally due to the reduction of consumption, which shift the market clearing cross to the left. Only small impacts concerning export were found in this thesis, while a great impact concerning export was seen in case with highest demand reduction for Dyrendahl. While this thesis move consumption around the year, Dyrendahl preforms a reduction in demand, as a result of new heating technology and local distributed power generation.

Altogether, the grade of comparability of the two thesis are perhaps a little thin. However, the way of modeling demand profiles seen in Tore Dyrendahl's thesis show how temperature dependency can be implemented more correctly in the demand profiles. A combination of ZEB's and demand response is a probable outcome in the future, so a combination of the two ways of modeling would be interesting.

8 Conclusion

In the modeling of demand response, the differences in sub-categorization and the subsequent change in demand profiles has proved to yield varied results. While *AreaAgg*, *OptFlex* and *Separation* were all provided with profiles generated in the Leopard model, with the same implemented assumptions of DR, the different partitioning, and thus assembly of the profiles, showed large variations. *Separation* showed the most stable consumption through the simulation period, all the while producing reduced prices compared to *Historical* values. Although there were no noteworthy profitability to the average household consumer, a positive socioeconomic benefit was shown. The main difference in this case to the other two was the change in temperature dependency, indicating its importance.

Considering the limited options to modeling DR in the EMPS model, combined with the lack of empirical data concerning DR, the demand profiles produced and used in this thesis are considered as a good start to modeling DR. However, the lack of price matching limits the consumer response. Thus, a closer relation to price signals should be developed, before a large scale implementation of DR in the EMPS model is done.

It is difficult to make a recommendation to which of the new modeling styles Statnett should adapt, as they all show measurable changes when simulated. As one should not choose a method based on ones desired outcome, it is not evident that the case which yields the most favorable results for DR, *Separation*, should be the preferred choice. However, Statnett should consider utilizing the adapted profiles from Optimeering and the Leopard model, in addition to the projected quantities used today. If such, an automated and less cumbersome way of conversion between the Leopard model and the EMPS model should be developed. A finer resolution of firm demand in the EMPS model would also be appropriate, so that changes in demand response can be done quicker and more easily. Nevertheless, this requires a more specific modeling of temperature dependency for each contract.

Lastly, one have to note that to generate value to the power and energy system, demand response must be considered as an interactive part of energy reduction measures. E.g. in combination with a higher implementation of zero emission buildings and/or the increase in intermittent renewable production. In a complex system, no part can or should be trusted to provide solutions alone. A combination of energy reduction measures is necessary to yield a sustainable power system.

Recommendations for further work

- With the activation of the power consumer, a need for more frequent adaptations of the consumption profiles might emerge. Large part of the preparatory work for the analysis preformed in this thesis consisted of understanding and utilizing the Leopard model, in addition to converting its profiles for use in EMPS. As several versions of the EMPS model is frequently used in Statnett's analyses, a simpler and more user-friendly way of converting the profiles would be recommended.
- As mentioned, the profiles utilized in this thesis were optimized to even out consumption, regardless of power price signals. If DR on a consumer level is to be modelled, the development of a price based optimization should continue.
- The temperature sensitivity of firm demand has proven to be of great importance through this thesis. A partitioning of firm demand contracts gave differing results, even when equal dependency was assigned each sub-contract. Additionally, the extraction of non-temperature dependent demand yielded visible changes, although a correction of this extraction was tried. Therefore, accurate profiles directly connected to specific consumption segments and categories should be developed, to generate more precise results.
- As the utilization of demand response is not exclusively found in the residential sector of general consumption, further studies should be made to include DR in the EMPS model, focusing on the service and industrial sector. These sectors uphold large parts of the Norwegian power consumption, and can therefore not be ignored in the consideration of an active electricity customer. Additionally, the modeling of power intensive industry holds great potential. Ultimately, a combination of all segments is favorable,

to capture the effect of all (hopefully) more active, future power consumers.

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A Exponential price elasticity of firm demand

This appendix refers to the preliminary study for this master thesis, conducted during the fall of 2016 (15).

Firm demand can be made price elastic using an exponential function:

$$W = \left(\frac{P}{P_n}\right)^e \tag{A.1}$$

W	=	percent of normal consumption
P	=	Market price $[cent/kWh]$
P_n	=	Normal price level $[cent/kWh]$
e	=	Exponent

The normal price level and the exponent is input from the user, and the relationship is illustrated in figure A.1.

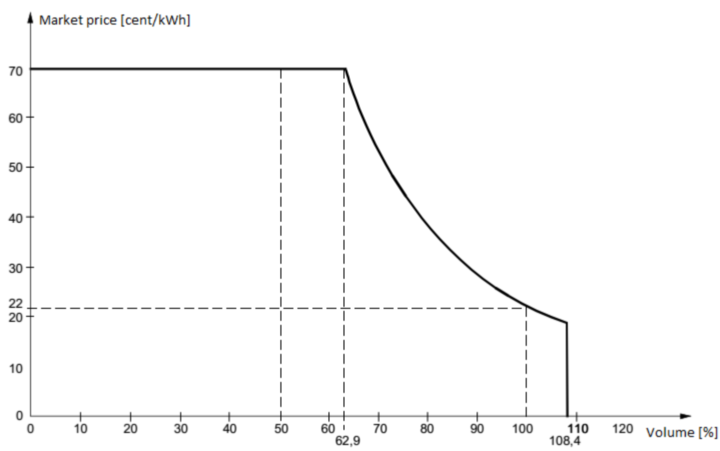

Figure A.1: Correlation of market price and firm demand when using exponential function (23)

The firm demand contract has a predetermined "normal" consumption volume, and equation A.1 calculates the usage percentage of this volume, as a function of the normal price and the hourly or weekly market price (depending on chosen resolution of simulation). If the market price exceeds the normal price, the demand will decrease, as seen in figure A.1. Here the normal price is 22 $cent/kWh$, at which the consumption is at 100 %. As market price increase, the consumption decrease exponentially, until the price reaches the disconnection price of the firm power. At this point, rationing will be necessary. The model does not allow consumption exceeding 100 % (24)(23).

B Overview inflow

Year	Norway
1988	138398
1989	162622
1990	165253
1991	127803
1992	149532
1993	133410
1994	136890
1995	149067
1996	01293
1997	143096
1998	137927
1999	147644
2000	163258
2001	133217
2002	126112
2003	129831
2004	137450
2005	162871
2006	130684
2007	158510
2008	143984
2009	138479
2010	117750
2011	169729
2012	147660

Table B.1: Total inflow in GWh for each simulated year in the model for Norway and (15)

C Weekly prices for all cases

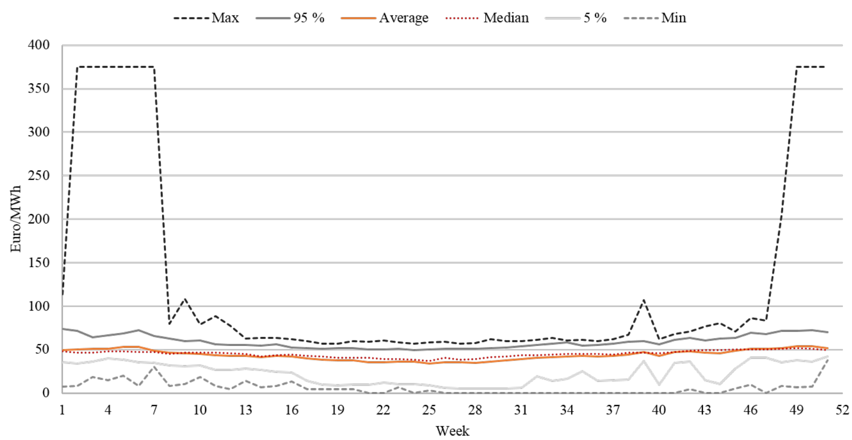

Figure C.1: Weekly prices, *Historical*

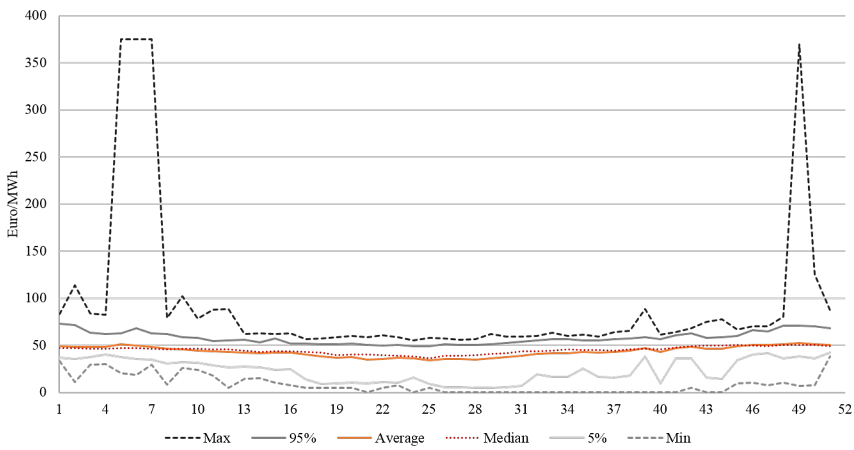

Figure C.2: Weekly prices, *Flat*

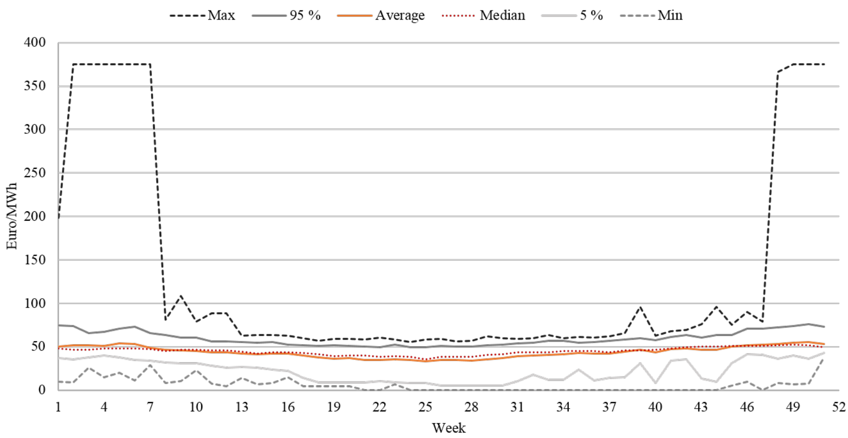

Figure C.3: Weekly prices

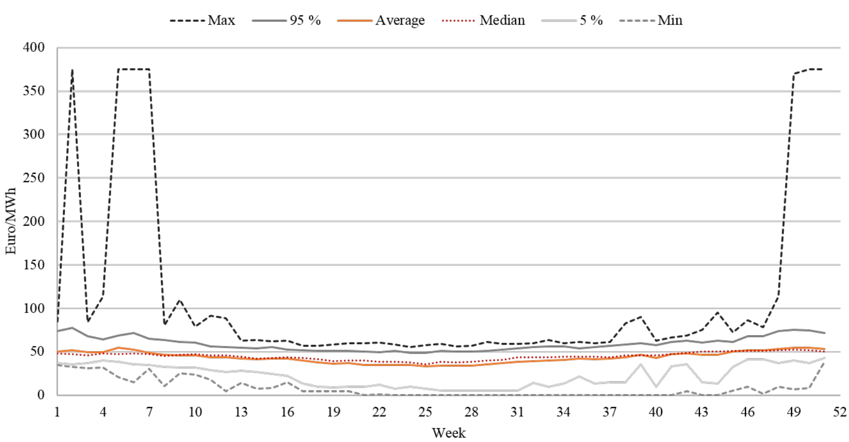

Figure C.4: Weekly prices

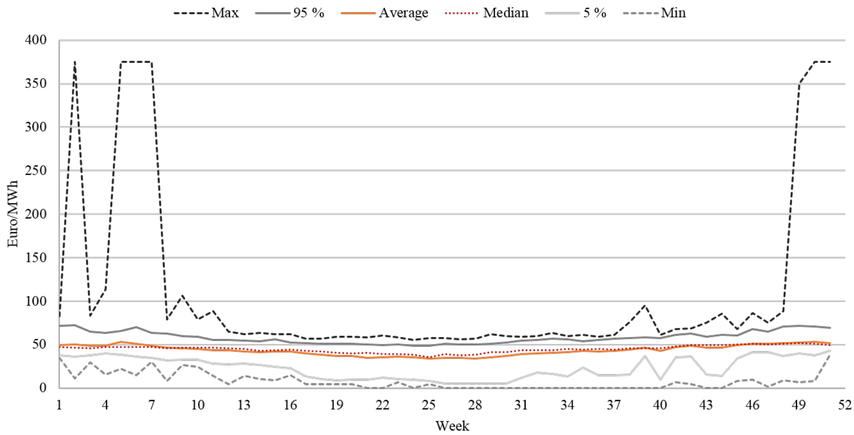

Figure C.5: Weekly prices

D Annual hourly prices for all cases

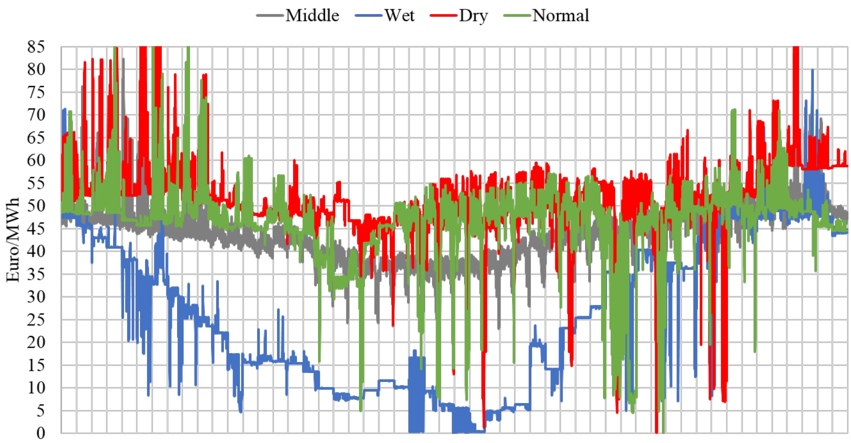

Figure D.1: Hourly prices through *Historical* wet, dry and normal year, including middle prices

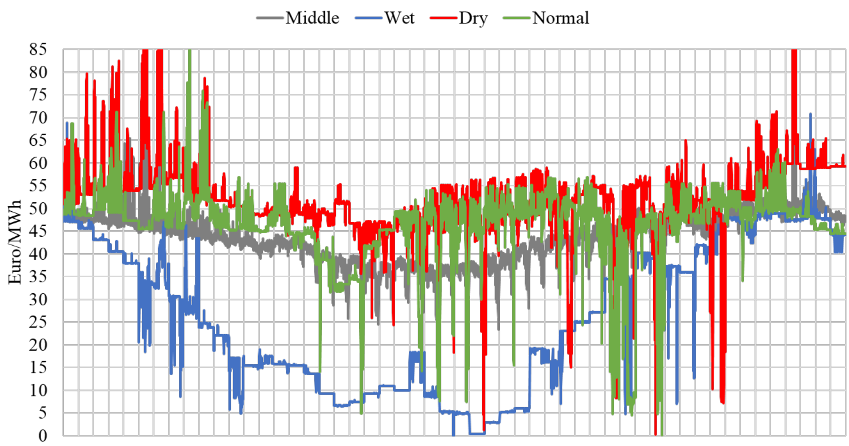

Figure D.2: Hourly prices through *Flat* wet, dry and normal year, including middle prices

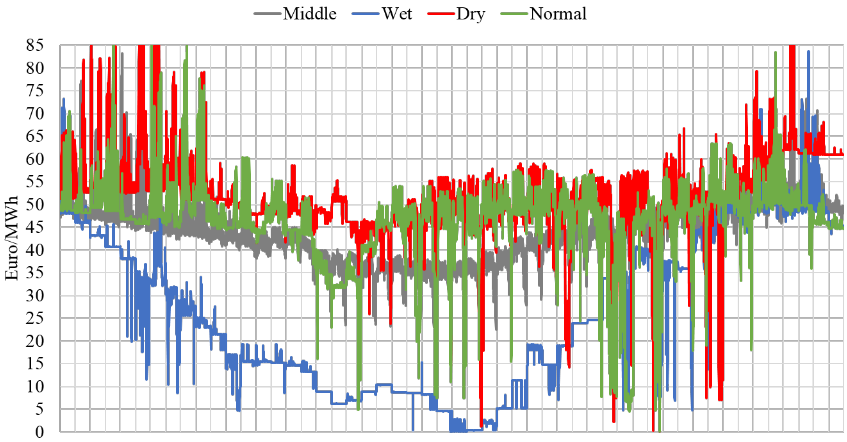

Figure D.3: Hourly *AreaAgg* prices through wet, dry and normal year, including middle prices

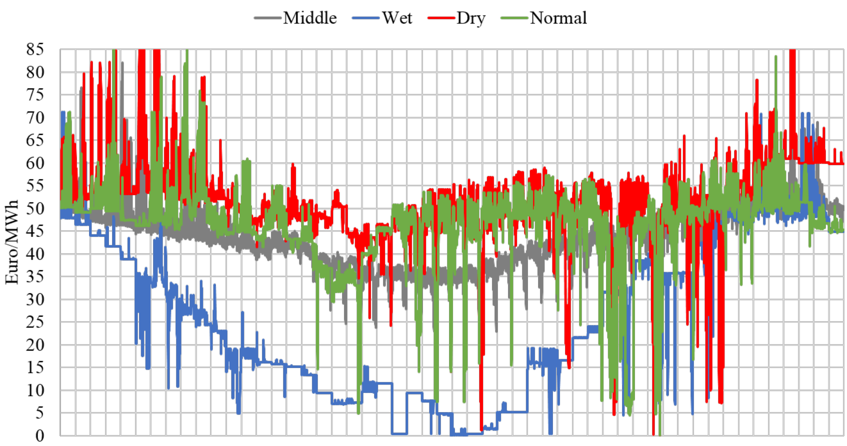

Figure D.4: Hourly *OptFlex* prices through wet, dry and normal year, including middle prices

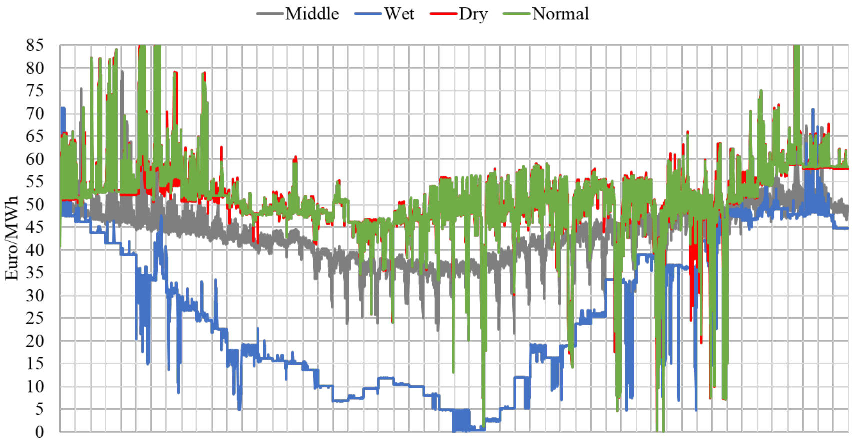

Figure D.5: Hourly *Separation* prices through wet, dry and normal year, including middle prices