Master's thesis

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Demand response in a short-term hydro-thermal multi market model.

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Abstract

With the increasing penetration of variable renewable energy sources, balancing services needed in the grid increases. Intermittent energy causes imbalances in the grid with its lack of flexibility and inertia, affecting the markets of trading power and optimizing the power balance. The importance of flexibility is increasing with the increasing share of power traded closer to the operation time and the fluctuation coming from variable energy resources.

In the future, there will be an increasing need for flexibility and controllability both on the demand and production side with a need for price forecasts for all electricity products. SINTEF Energy Research has developed a short-term multi market model, PriMod. It optimizes the power scheduling in a better approach and calculates the marginal cost for all physical products on a finer time scale. The flexibility on the consumer side has not yet been formulated, and model demand response in a more accurate hydropower scheduling model could decrease the price.

This master thesis investigates the impact of price-based demand response in weekly scheduling of hydropower in the Nordic system. The object is to model demand response into PriMod with the focus on the residential side to capture its impact. Methods implemented are gradual adaption of consumption and demand side management with the focus of price-based demand response where the price adjust the consumption.

The results showed that the impact price-based demand response had on the weekly scheduling model, PriMod, was a decrease in the price, peak-demand, and demand when the prices in the system and area were above the compensation cost of demand side management. Further, price-based demand response led to a decrease in investment costs in the grid and a lower electricity bill. From the seasonal variations, the greatest decrease in price was in the winter which was 1.68% while the summer and fall were 0% due to low prices. Results regarding reservoir level showed a marginal effect as the water values were the main variable that affected the price. The water value is though affected indirectly by price-based demand response as it decreases with the increasing potential of demand response. When flexible loads were increasing it had a good effect with an increasing impact. Altogether this shows a marginal difference for an end-user, but for the social welfare this will have a great impact due to a decrease in the network charges.

Moreover, demand response can contribute to the balancing market under reserve mechanism where they have a great potential to work as a faster frequent reserve in the Nordic balancing market. Demand response has the potential to work closely with all markets as long the assumptions are well formulated and tested as this is one of the greatest barriers towards demand response. The further work of both reserves, how to further implement demand response into balancing services models and motivation for a formulation a new tariff structure is presented.

Sammendrag

Med den økende andelen av variable fornybare energikilder har behovet for mer balansering i nettet økt. Dette gjennom at disse forårsaker ubalanser i nettet ved at deres potensial for fleksibilitet er lavt og det samme med tregheten.

I fremtiden vil det være et økende behov for fleksibilitet og kontrollerbarhet både på etterspørsel- og produksjonssiden med behov for prisprognoser for alle produkter. SINTEF Energy Research har utviklet en kortsiktig modell for prisprognosering, PriMod. Den optimaliserer kraftplanleggingen med en bedre tilnærming og beregner marginalkostnadene for alle fysiske produkter på en finere tidsskala. Fleksibiliteten på forbrukersiden er ennå ikke formulert her, men er et økende behov siden dette kan redusere prisene i systemet.

Denne masteroppgaven undersøker effekten av prisbasert forbruksrespons gjennom ukentlig planlegging av vannkraftproduksjon i det nordiske systemet. Formålet er å modellere prisbasert forbruksrespons i PriMod med fokus på husholdninger for å fange opp dens påvirkning på systemet. Implementerte metoder er gradvis tilpasning av forbruk og demand side management med fokus på prisbasert forbruksrespons hvor pris justerer forbruk.

De viktigste resultatene viser at prisbasert forbruksrespons vil redusere pris, forbruk i peak hours og forbruk når prisene i systemet og områdene er høyere enn kostnadene for kompensasjon for demand side management. Prisbasert forbruksrespons kan føre til en nedgang i investeringskostnader og lavere strømregninger. Det er sesongvariasjoner, hvor den største prisreduksjon er på vinteren med 1.68%, mens om sommeren og høsten er potensialet lik null på grunn av lave priser. Forskjell i reservoarnivåene har marginal effekt når det gjelder prisbasert forbruksrespons. Det var funnet at vannverdiene var variabelen som påvirket prisen her. Vannverdi ellers påvirkes indirekte av prisbasert forbruksrespons. Den avtar med det økende potensialet for forbruksrespons. Resultatene viser en marginal forskjell for sluttbrukere, men for samfunnet vil dette ha stor påvirkning grunnet reduksjon i nettleie og investeringskostnader. Forbruksrespons kan bidra i balansemarkedet med raskere reserve enn vannkraft. Så lenge forutsetning for forbruksrespons er godt formulert og testet kan det bli brukt i kraftmarkeder og kortsiktige prisprognoser.

Preface

This master thesis was accomplished in the fall semester of 2019 and concludes my Master of Science (M.Sc) degree in Energy and Environmental Engineering with the Department of Electric Power Engineering at the Norwegian University of Science and Technology, NTNU. It was written under the supervision of Associate Professor Hossein Farahmand and co-supervisor Research Scientist at SINTEF Mari Haugen.

I am grateful for all guidance, support, and encouragement throughout this fall given by my supervisors, but also letting me get more insight into the power market and given me knowledge that I am sure will help me beyond my studies. Further, I would extend my gratitude to the researchers at SINTEF Energy Research for providing the PriMod model, given me insight into the model, and help with understanding the model and implementation of the script.

Last, but not least, I would like to thank family and friends for motivation and good advice when needed and further understanding that new challenges can be difficult and frustrating.

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Table of Contents

Abstract i

Sammendrag iii

Preface iv

Table of Contents vi

List of Tables vii

List of Figures x

Abbreviations xi

Nomenclature xiii

1 Introduction 1
- 1.1 Background 1
- 1.2 Motivation 2
- 1.3 Problem formulation 3
- 1.4 Outline 4

2 Theoretical background 5
- 2.1 The Nordic power market 5
- 2.2 Demand Response 11
- 2.3 Hydro-thermal power scheduling 19

3 PriMod - a short-term hydro-thermal market model 23

3.1 The strategic model 23
3.2 The operational model 25
3.3 Pricing 26

4 Modeling Demand Response 27
4.1 Gradual adaption of consumption 27
4.2 Demand side management 29
4.3 Implementation 31
4.4 Data 33

5 Case studies 37
5.1 Seasonal variations 38
5.2 Change in reservoir level 51
5.3 Flexible loads 54
5.4 Discussion 56

6 Conclusion 59

Bibliography 67

Appendix 69

List of Tables

4.1 Cost for flexible firm demand. 35
4.2 Compensation cost for each area in mu/MWh. 35
4.3 Percentage shiftable and curtailable for each area. 36
4.4 The median of the reservoir level for the given week [56]. 36

5.1 Peak demand change in percentage in winter. 38
5.2 Change in demand and price in each area in the winter. 40
5.3 System demand and price changes in the winter due to DR. 42
5.4 Peak demand change in percentage in spring. 42
5.5 Change in demand and price in each area in the spring. 44
5.6 System demand and price changes in the spring due to DR. 45
5.7 System demand and price changes in the summer due to DR. . . . 47
5.8 Total peak demand change in percentage per season. 49
5.9 Change in demand and price in each area per season. 50
5.10 System demand and price changes in the winter due to DR. 50
5.11 Change in demand and price compared to reservoir level of 68.5% for the whole periods. 52
5.12 Change in system price and demand compared to reservoir level of 68.5%. 53
5.13 Change in system due to load shifting. 55

List of Figures

2.1 Activation time for each of the capacity markets. The purple line indicates the inertia in the system. [27] 7
2.2 Pricing schemes. From top to bottom, TOU, RTP and CPP [33] . . 12
2.3 Peak clipping [35] 13
2.4 Valley filling [35] 14
2.5 Load shifting [35] 14
2.6 Demand and supply curve [36]. 15
2.7 Demand profile for instantaneous, asymptotic and linear adaption [37]. 16
2.8 Priority loads [38]. 17
2.9 Scheduling hierarchy [36] 19

3.1 Strategic and operational model coupling [20] 24

4.1 Flow chart of demand side management. 29
4.2 Flowchart for the weekly optimization for price-based demand response. 31
4.3 Flowchart for the optimization model of price-based demand response. 32
4.4 Connection between areas in data set. 33
4.5 Firm demand that is given in the data for a week. 34

5.1 Change in demand in each area due to demand response in the winter. 39
5.2 Change in price in each area due to demand response in the winter. 39
5.3 Change in demand due to load shifting and curtailment in the winter. 41
5.4 Changes in the system price and demand due to demand response in the winter. 41

5.5 Change in demand in areas due to demand response in the spring. 43
5.6 Area price changes due to demand response in the spring. 43
5.7 System demand and price changes due to demand response in the spring. 44
5.8 Demand change in each area in the fall due to DR. 45
5.9 Price change in each area in the fall due to DR. 46
5.10 System price and demand change in the fall due to DR. 46
5.11 Demand change for each area in the fall due to DR. 48
5.12 Price change for each area in the fall due to DR. 48
5.13 System demand and price change in the fall due to DR. 49
5.14 Area demand with a changing reservoir level. 51
5.15 Area prices with a changing reservoir level. 52
5.16 System price and demand variations with varying reservoir levels. 53
5.17 Amount shifted demand for different levels of flexible loads. . . . 54
5.18 System price and demand change 55

6.1 Load shifting and curtailment spring. 70
6.2 Load shifting and curtailment summer. 71
6.3 Load shifting and curtailment fall. 72

Abbreviations

Symbol	=	definition
AMS	=	Automatic metering system
CPP	=	Critical peak pricing
DER	=	Distribution energy resource
DSO	=	Distribution system operator
DSM	=	Demand side management
DR	=	Demand response
EV	=	Electrical vehicles
SDP	=	Stochastic dynamic programming
SFP	=	Scenario fan problem
SFS	=	Scenario fan simulator
RTP	=	Real-time pricing
TOU	=	Time of use pricing
TSO	=	Transmission system operator
VER	=	Variable energy resources

Nomenclature

Indices and sets	
$k \in \mathcal{K}_t$	Time steps in week t.
k'	Time step equal to k, but in week t-1.
$n \in \mathcal{M}_a$	Market steps per area.
$a \in \mathcal{A}$	Areas.
$p \in \mathcal{S}_r^{PQ}$	Segments of piecewise linear PQ.
$r \in \mathcal{R}_a$	Reservoirs in area a.
$s \in \mathcal{F}_a$	Flexible firm demand market steps per area.
$t \in T$	Time horizon, 1 day.
T^s	Subset of T where you can shift demand.
T^c	Subset of T where you can curtail demand.

Parameter	
$\mathcal{L}_{a,k}$	Firm demand in area a, step k.
$\mathcal{W}_{a,k}$	Wind production in area a, step k .
$\mathcal{M}_{n,k}^{price}$	Market cost at step n, step k.
$\mathcal{T}_{j,i}^{loss}$	Transmission loss from area j to i.
$\mathcal{P}^{bypass}$	Bypass penalty.
$\mathcal{P}^{spill}$	Spillage penalty.
$\mathcal{P}^{tank}$	Tank water cost.
$\eta_{r,p}^{PQ}$	Generation efficiency per PQ segment p.
$\mathcal{H}_r^{h/h_0}$	Relative head at r, referred to initial reservoir.
$\mathcal{Q}_r^{pump}$	Pump power in reservoir r.
$\mathcal{P}_{a,k}$	Area price in area a, step k.
$\mathcal{C}_{s,k}^{price}$	Market cost at step s, step k for flexible firm demand.
$m_{n,k}^{cap}$	Market capacity at step n, step k for price elastic demand.
$y_{s,k}^{cap}$	Capacity on step n in period t for flexible firm demand.
$\delta_{a,k}$	Share of the firm demand that is flexible in area a, step k.
$\beta_{a,k}$	Inertia parameter for adaption in area a, step k.
$\mathcal{C}_{a,t}^{comp,c}$	Compensation cost of curtail in area a, time step t.
$\mathcal{C}_{a,t}^{comp,s}$	Compensation cost of shifting in area a, time step t.
$W_{a,t}^{c}$	The share of the total load that can be curtailable in area a, time step t.

$W^{s}_{a,t}$	The share of the total load that can be used for load shifting in area a, time step t.
W^{min}	95% of the off-peak demand with the day that is optimized.
W^{peak}	Peak demand for shiftable loads.

Variables

α	Future profit function.
$q^{bypass}_{r,k}$	Bypass in reservoir r, step k.
$q^{spill}_{r,k}$	Spillage in reservoir r, step k.
$q^{tank}_{r,k}$	Tanking in reservoir r, step k.
$q^{dis}_{r,p,k}$	Discharge in reservoir r, segment p, step k.
$q^{pump}_{r,k}$	Pumping in reservoir r, step k.
$m_{n,k}$	Price elastic power at step n, step k.
$t_{j,i,k}$	Transmission of power from area j to area i.
$\mathcal{D}_{a,k}$	Inelastic firm load in area a in time t.
$y_{s,k}$	Flexible firm demand consumption on step s in time period k.
$\omega_{a,t}$	New shiftable demand in area a, step k.
$\chi_{a,t}$	New curtailable demand in area a, step k.
z	Binary variable that is set due to restriction of the price.

Chapter 1

Introduction

1.1 Background

The energy sector has over the last 30 years changed with the implementation of new energy resources and the deregulation of power as seen in the 1990s in the Nordic system [1]. The introduction of new markets that make it easier for renewable energy sources to compete with coal and gas has entered the market with the electrical certificates market and the CO_2 market that give incentive to build renewable energy power production and add an extra cost to the non-renewable energy sources making the cost of producing power too high for the market to accept [2, 3].

The electricity mix before consisted of a high share of non-renewable sources. Due to the climate changes we are upon the need for changes is a fact. In Europe, the EU commission is aiming for a greener future with goals for 2020 and 2030 to reduce greenhouse emission and increasing green technology to produce power [4]. From 2010 to 2018 there was an increase in the share of renewable from 20% to 32% in the EU countries [5]. Especially the share of wind with an increase of 67% and causing the European system to have more energy that is variable know as variable energy resources. These resources are creating a need in the energy sector to have more security in the grid, but also implementing reserves mechanisms that are responding more quickly to the changes in the system to make sure there is a balance between supply and demand at all times. This has created a need to model the balancing of demand and supply side towards a shorter time. The call-out for a time resolution of 15 minutes has been seen in [6, 7], where there it is stated that with a 15 minute time resolution structural imbalances will decrease as this errors are made up from market design and the demand within an hour varies which will need the TSOs to activate reserves more often. Having a 15-minutes time resolution the imbalances will decrease and further lead to having less reserves for balancing needs.

SINTEF Energy Research developed a project that focuses on the balancing needs in a short term multi market model. The primary objective of the project developed, PRIBAS, is to design, develop and verify a model concept that can compute the marginal prices for all physical electricity production in the Nordic power market. These products include energy and different types of reserve capacity and balancing energy. The development of the model, PriMod, has been going on from 2017 towards 2019. It has been developed and researched throughout the years with start and stop costs for thermal production, reserves for up-and down-regulation and flow based market coupling [8, 9, 10]. The flexibility in the model was stated in [11] as underestimated on the consumer side while the production side was overestimated.

1.2 Motivation

Flexibility in the grid is essential when handling balancing services. It can either come from the production side, which is the traditional method, or the demand side, which is not highly used in the Nordic system due to its large reservoir in Norway. The need for battery storage for flexibility is not a profitable investment perceived in [12] since hydropower already works well as a service for reserves in the market as they can respond quickly to imbalances in the system compared to thermal generation. Due to intermittent generation that interferes with the inertia in the system Statnett has introduced FFR, a reserve that is going to work faster than FCR that has an activation time of 1-2 secs [13]. Statnett found that hydropower generators did not qualify to be actors for this reserve. Hence there is a need to have demand response as a reserve that can respond faster and can qualify for FFR.

Demand response is a broad topic that has been researched a lot during the last decades. Every day new articles about demand response and flexibility are published, as this is highly important to discuss concerning the future of the energy sector. Even though it's been researched in a great extension there is not much literature about demand response where it is providing balancing services [14], but also when it comes to modeling it in hydro-power scheduling models. Though many articles focus on load forecasting where artificial intelligence has been used to support the power market as this can aim at modeling the demand more correct as the consumers are sensitive to prices. Some of the technology and methods used in AI are neural network and vector regression as some to mention [15, 16, 17]. An approach to achieve demand response without AI is seen in [18] where a demand elasticity matrix is modeled to account for flexible consumers. The matrix is a price elasticity matrix that accounts for the normalized-self and cross-price elasticity.

Scheduling of hydropower and loads are important as this can decrease the wind power curtailment and system scheduling cost when assumed the modeling of hydropower generation assets in the generation scheduling problem is modeled accurately [19]. Having demand response in hydropower scheduling can decrease the prices even further. This set a focus on the need for more energy storage, demand response, and faster reserves in the balancing market to cope with the variable energy resources. With this and the lack of demand response that provide balancing services, there is a need to research how demand response can be modeled accurately into a short-term hydropower scheduling and the impact it has.

1.3 Problem formulation

This thesis is formulated on the research question *what is the impact of price-based demand response on weekly scheduling of hydropower in the Nordic system?* To answer this question PriMod is going to be used to test and implement price-based demand response.

PriMod is a deterministic short-term hydro-thermal model that is developed under the PRIBAS project from SINTEF Energy Research. It focuses on implementing a model to calculate the marginal cost for all physical products on a finer time scale [20].

The scope of the master thesis will be to further develop PriMod. The development will be to carry out restrictions and new methods to achieve demand response in the system on an aggregated level, analyze the system towards the geographical situation, seasons and availability of flexible demand and look at the effects of demand response for the residential sector. The focus will be on the Nordic system with hydro and thermal power areas. There will be used programming where Python is the language used with the optimization model Pyomo and CPLEX as the solver.

The contributions to uncover the impact of price-based demand response in the weekly scheduling model, PriMod, is to model:

- Gradual adaption of consumption
- Demand side management
  - Load shifting
  - Curtailment (peak clipping)

The work-flow of the thesis will first be to get a good overview and understanding of the model developed, PriMod, and the implementation of the script provided by SINTEF Energy Research. Further, investigate other models within the hydropower scheduling while research demand response. In the end, price-based demand response will be implemented into PriMod and then solve the model to see the impact of the price-based demand response with different cases towards a base case based on the Nordic system.

1.4 Outline

The rest of the thesis is constructed like this:

Chapter 2 will present background information for the power market, demand response and hydropower scheduling.

Chapter 3 presents PriMod with its two modeling layers, how the model works and its aim.

Chapter 4 presents the modeling of price-based demand response. Both the gradual adaption of consumption and demand side management towards load shifting and curtailment. Limitations and restriction are presented in the modeling part, the implementation and the choices for data is presented.

Chapter 5 present a case study with three different studies. Here seasonal variations, change in reservoir level and the increase of flexible loads. Results and discussion around the impact price-based demand response are presented.

Chapter 6 concludes the thesis and presents further work of price-based demand response that needs to be further discussed.

Chapter 2

Theoretical background

In this chapter, there will be researched topics regarding the power market, hydropower scheduling, and demand response. This is to get a good overview of the Nordic system as to how it operates, how power scheduling is working over the time horizon and how the different models are connected. Demand response needs to be investigated to see the benefits, challenges, and motivation for implementing it into a weekly scheduling model.

Parts of this chapter has been taken from my specialization project, *Modelling demand response in a short-term hydro-thermal model*, written in the spring semester of 2019.

2.1 The Nordic power market

For the last 30 years, the Nordic power market has gone through changes as deregulation of the power market, the introduction of full competition in the market and also a market where countries have entered to support trading across borders.

The Nordic power market consists of several markets of trading. The markets are the financial market, day-ahead market, intraday market, and the balancing market. Where the financial market is traded in NASDAQ, the day-ahead and intraday market in Nord Pool while the balancing market is organized by the TSO within each country. All of the markets are working together to establish a balancing system and obtain the highest possible social welfare.

Below the physical markets are presented and given information for how the markets are carried out.

Day-ahead market

The main area of trading of power takes place in the day-ahead market. Market actors trade power here through bidding on a daily basis. Nord Pool supports the Nordics, Baltics, Central Western Europe and the UK with its day-ahead market that was established in the early 1990s and expanded throughout the years. The market focus on selling and buying energy for the next 24 hours every day throughout the whole year. It endeavors to maximize the social welfare [21] where the market is cleared within different bidding zones [22]. The bidding zones is based on transmission constraints and geographical situation. In Nord Pool, there is possible to trade in 14 countries across 21 bidding zones.

The bidding happens in an orderly form where producers and consumers bid in the market. They report to the market how much power, in volume, at what price they need or can produce in all 24 hours [21]. The bids have to be submitted into the Nord Pools system by 12.00 CET the day before. After the submission deadline, the bids are matched and the power prices are calculated. The prices calculated are the system and area prices. The system price is the reference price for the whole system while the area price is the price for the bidding zone and is calculated on the bids within the bidding zone and with transmission cost. Results are published at 12.42 CET and are used as a baseline for the planning the next 24 hours.

Intraday market

After the day-ahead market closes the intraday market opens. It supports the day-ahead market with balance supply and demand further as the bidding takes place closer to the delivery hour. The bidding starts at 14.00 CET and closes one hour before the delivery hour. Market actors have the possibility to change their commitments from the bids made in the day-ahead market as they want to balance out their portfolio. They place bids into the market where the principle of first-come-first-served is practiced as best prices come first – highest buy price and lowest sell price [23].

The market covers the Nordic, Baltic, German, Luxembourg, French, Dutch, Belgian and Austrian markets [24]. The reason is that the Nord Pool intraday market was on 12^{th} of June 2018 supported by the European cross-border Intraday market solution (XBID) [24].

The Intraday market has been seen as increasingly important due to the increased share of variable energy resources, as wind and solar power, in the grid and the market can as mentioned support the day-ahead market with more precise bidding. Traded volume in the intraday market has from 2014 to 2018 increased with 69% while the day-ahead 10% [25, 26]. This can be seen in contrast to the increasing share of VER in the system. It creates imbalances in the system and has increased over the years. Hence the intraday market can support the power system with the availability to support the market with the unforeseen need for flexibility. The development around the intraday market is therefore seen as increasingly important due to VER.

Balancing market

Though the intraday and day-ahead market are balancing the supply and demand, there are still need of balancing closer to the operation time as system faults may happen. It is the TSOs in the different regions that are responsible for this market. They are responsible for the procurement of ramping flexibility and aim at restoring the balance in the system as the frequency [1, 22]. The market is seen as a real-time market as the activation time is from real-time up to 15 minutes.

The balancing market in the Norwegian system is divided into two markets, the capacity and activation market. The capacity market consists of FCR, aFRR, and mFRR (RKOM) while the activation market is mFRR (RK). Each of the markets has a different time of activation, and they are following each other with the balancing need in the grid as shown in figure 2.1.

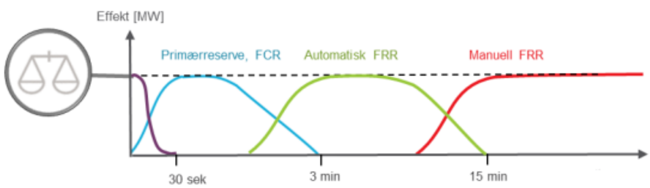

Figure 2.1: Activation time for each of the capacity markets. The purple line indicates the inertia in the system. [27]

To participate in the balancing market, each actor has to be a balancing responsible actor or have an arrangement with another balancing responsible actor. The balancing responsible actor is the one that takes care of the market for the producers. They bid in the market, deliver production plans, ensure activation, and receive payment for capacity and activation for imbalances from the TSO [27]. To participate in FCR producers with an effect of more than 10 MVA has to fulfill requirements set by FIKS [27]. Full prequalification is only needed when participating in aFRR where the actor has to be a balancing responsible actor. In RKOM the producer itself can make bids, but need a balancing responsible actor.

Frequency Containment Reserves - FCR

The primary reserves known as Frequency Containment Reserves, FCR, is fully automatic reserves that help maintain the frequency balance in the system as it is activated due to deviation in the frequency [28]. The reserves are divided into FCR-N and FCR-D, where they handled normal deviation reserves and disruption operation reserves respectively.

To secure the market with primary reserves there is a weekly and daily market established where the procurement is before and after the day-ahead market respectively [27]. The daily market covers the lack of reserves that have not been made in the weekly market and the day-ahead market. The capacity needed in the FCR-D market is 350 MW and 212 MW in the FCR-N market [28].

Automatic Frequency Restoration Reserve - aFRR

The secondary reserves, aFRR, are fast responding reserves that bring the frequency back to 50.00 Hz. The reserve releases FCR such that there are reserves in the system to handle other imbalances that might happen closer to the fault [29]. These are automatic reserves where the TSOs send signals to producers where the reserves are activated within two minutes. In the Nordic country, the volume needed in this market is 300 MW.

This market is relatively new with the implementation in the Nordic system in 2013 [27]. From Fall 2019 there is established a Nordic capacity market for how to distribute the reserves in an effective approach. The market is now working in the approach where all the Nordic TSO are collaborating. They decide what type of volumes they are to purchase, when to use them and how they are to be distributed between all the countries [29].

Manual Frequency Restoration Reserve - mFRR

mFRR is tertiary reserves, which are manual reserves, that are used to handle congestion and deviation in frequency between and in bidding zones. These reserves have an activation time of maximum 15 minutes. mFRR consists of two markets, RKOM and RK. The first one is the capacity market and the latter is the activation market. They work together to make sure there are enough reserves for up and down regulation, and that the reserves are activated at the right time and order. In Norway, the mFRR capacity needed is 1700 MW to secure the dimension of fault in the system.

- **The reserve power option market (RKOM)**
  RKOM is making sure that there are enough reserves for up regulation. The actors that participate in this market will get paid for their participation in RK. Power intensive industry can here contribute with flexibility as both producers and consumers can participate in this market with up and down regulation.

- **Regulerkraftmarkedet (RK)**
  RK is the activation market for the mFRR reserves. The reserves are activated here and is common for the Nordic balancing market. Since these reserves are manual the TSOs, Statnett as an example, sends a signal through a SCADA to SCADA system between them and the actor to activate the reserves [27].

Expansion of the market

As the power system is changing, the establishment of new market schemes and development is needed. Due to the increasing share of VER, there is a need to look into new balancing markets that will support new challenges the power system is facing today and in the future.

The Nordic balancing model is a program that is established to optimize the balancing mechanism in the Nordic system. It will encourage the increasing share of VER in the system, the European market integration, and also aim at improving the balancing market efficiency [30]. The model is based on that the Nordic power system is moving from ACE to MACE control. Within the program, they are prioritizing the implementation of the 15 minutes time resolution. Further, the establishment of a Nordic aFRR and mFRR capacity market, mFRR energy activation market and a single price model [30].

Due to the increased transfer capacity between synchronous areas, more renewable production in the power system, the phase out of nuclear power plants and new consumption patterns there is seen that the inertia in the system, that handles the system stability in terms of transient frequency stability, can be too low and creates imbalances in the system that need to be handled before FCR [13]. A suggestion to preserve the balance in the system is the implementation of Fast Frequency Reserves (FFR). FFR are reserves that are activated before FCR to supplement it since FCR leads to unacceptable risk to frequency stability during critical situations within the year. FFR has a response time of 2 seconds, an activation time of 30 seconds and a rest time of 15 minutes. To prequalify for this was difficult. The pilot project of Statnett in [13] stated that demand reduction was the preferred option of FFR were both the industry of Hydro and Tibber with the reduction of aggregated electrical vehicles were passing the prequalification of FFR. While hydropower had difficult to respond as quickly as 2 seconds. This indicated that reserves options that had traditionally been used for up-and down-regulation are not sufficient enough for the system and new technologies have to be established for the hydropower sector, but also for demand response technologies to support the system with FFR.

2.2 Demand Response

The broad topic of demand response has been heavily discussed throughout the last decades as how to use and implement it. Demand response is in [31] defined as the *benefit for the security for balancing services in the grid*. In the research paper, there is a wide range of benefits and challenges presented towards demand response. Benefits mentioned are the implementation of IT systems since it is an attractive option to use demand response to secure power system flexibility. Demand response can meet fluctuations of the generation coming from renewable energy resources, making it favorable to increase the production of wind power. Also, the system cost of integration can decrease. On the planning side, demand response can result in a reduction in the substantial cost as DR reduces the capacity requirements in the system. Stated in [6] DR may be realized without any great costs or substantial structural changes making it favorable to use.

Barriers towards implementing DR mentioned are the current regulatory and tariff structure. The structure of how the consumers see the price of electricity is not evident due to network charges. This will make it difficult for consumers to respond to the price effectively. With the implementation of AMS, this barrier might decrease. Another barrier is the lack of appropriate market mechanisms in the current market structure. The mechanism now requires that the planning of DR happens hours ahead which makes it difficult for DR to participate effectively in the power market. The greatest barrier is the uncertainty concerning DR, where there is a lack of experience and that models and evaluation of DR are done under extensive assumptions [31]. Demand response and market models which are not modeled accurately will make it difficult to anticipate the real benefits of DR. A solution to business and market models is the entry of an aggregator in the system which is bidding into the market with its demand portfolio and will provide flexibility.

Price-based demand response

Another definition of demand response is defined in [32] as *a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, to give incentive payments designed to lower electricity use at times of high market prices or when grid is jeopardized.* This definition states that demand response is price based where the consumers' behavior of changing their consumption is due to the price.

The definition underlay that to favor demand response it has to be visible for the consumers what they are paying for their electricity, but also market actors that help consumer optimize their consumption. Previously, the electricity price was not visible for the consumer until they got their electricity bill, but could get a sense of feeling of the price from news and previous billing. Now, this has changed with the entry of AMS where consumers can automatically see the electricity price. The price shown is the variable price known as real-time price. The total price the consumer is paying is known as the tariff. This can be constructed in different approaches and can be known as a source of price based demand response.

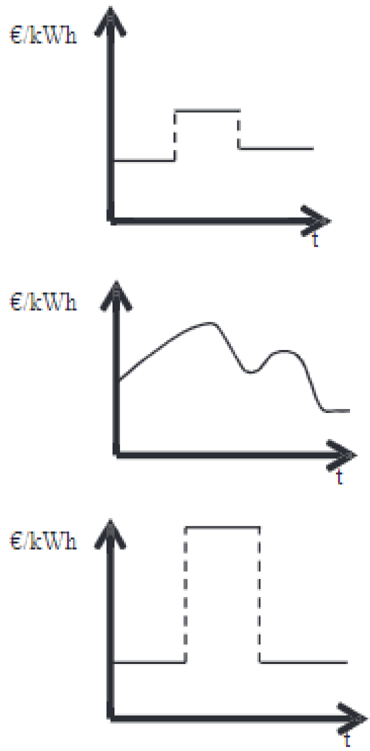

Figure 2.2: Pricing schemes. From top to bottom, TOU, RTP and CPP [33]

Price based demand response is defined in [33] as *changes in electric usage by end-use customers from normal consumption patterns in response to changes in the price of electricity over time*. The future suggests that pricing schemes that may support price based demand response are time of use, real-time pricing, and critical peak pricing. Time of use is fixed pricing within different time slots, real-time pricing is pricing that follows the price set in the day-ahead market and critical peak pricing is a high fixed price for certain time slots within the year. These types can be implemented into the system as the type of tariff and are presented in figure 2.2. The choice of the tariff will impact the grid due to consumers' relation to price and how they act when it comes to their consumption.

Demand side management

Demand side management is a method to account for the price based demand response where demand side management (DSM) is defined in [34] as *initiatives and technologies that encourage consumers to optimise their energy use*. Incentives through laws, regulations, and tariffs are possibilities to obtain DSM. Also, technologies around smart grids with the increasing share of AMS and smart appliances in households are technological solutions that favor DSM.

These incentives and technology can support the grid with demand response through both direct and indirect control. For the direct control there are TSOs and also companies (Tibber) that are offering smart systems, that will regulate the demand side. Tibber can aggregate the demand for consumers such that they can achieve a lower electricity bill while not decreasing the comfort of the end-user. On the other hand, indirect control is where the consumers are changing their consumption due to tariffs and prices set by the market. This means that the TSOs can set the grid tariffs so that they can influence the consumers to change their consumption.

There are several methods of demand side management. Below there is presented three types.

Peak clipping

Peak clipping is a method that aims at reducing demand during peak hours. There is imposed a curtailment or a cut in loads some hours in the day as the demand exceeds the capacity of the grid. The ones that can impose this type of curtailment are TSOs and DSOs, but also companies as Tibber that handle the planning of consumption on behalf of the consumer given that the consumer has an agreement with them.

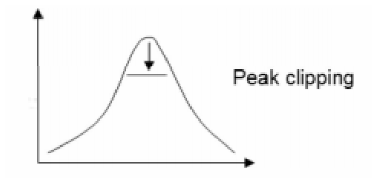

Figure 2.3: Peak clipping [35]

This technique is beneficial for reducing grid investments and securing the grid from outages. End-user can though be impacted by this DSM through CPP which is a tariff that will impose a high price in some hours and end-users can get an incentive to cut their consumption here.

Valley filling

Valley filling is another method that is technically the opposite of the peak clipping as it increases loads during off-peak hours. TOU is a type of tariff that has incentives for valley filling as the price is high in peak demand hours. This may be beneficial when there is excessive production of power from VER as an example.

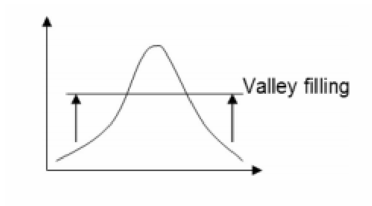

Figure 2.4: Valley filling [35]

Load shifting

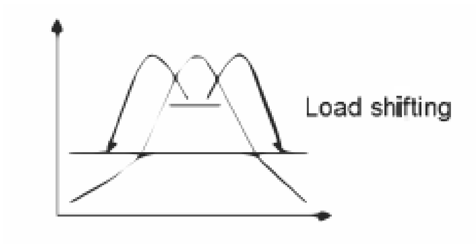

Figure 2.5: Load shifting [35]

Load shifting can be perceived as a combination of peak clipping and valley filling since it moves loads from peak to off-peak hours due to congestion in the system or that the prices are high. Implying that when there is direct control you can move the load such that you do not risk extending the grid capacity and avoid curtailment. Indirect control is that the consumers see a high price due to tariffs and will shift their demand towards off-peak hours. This can be uncertain since we don't know how the consumers respond to prices as this is one of the barriers concerning demand response.

Flexible demand

Demand can be divided into two groups, inelastic and price elastic demand [36]. Where inelastic demand refers to firm demand. Traditionally the modeling of demand consisted of only firm demand and price elastic demand. In the early 2000s, there was seen that the firm demand had some elasticity [36]. In figure 2.6 the supply and demand curves are illustrated. FD is the firm demand, while ED1-4 is the price flexible firm demand and FL1-4 price elastic demand. EX1-2 is price elastic and is the export.

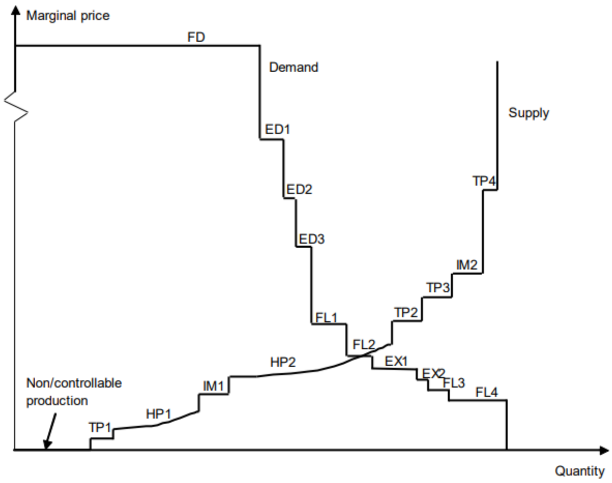

Figure 2.6: Demand and supply curve [36].

Since there is possible to defined price flexible firm demand in EMPS there has been adjusted a new functionality, gradual adaption of consumption. This method provides a more realistic approach for modeling flexible demand as it adjusts the consumption of each step depending on the consumption and price from the last period. The adjustment happens both on the price elastic and flexible firm demand steps where it adjusts the consumption either linear or asymptotic [37].

The method adjusts the consumption from week to week, mainly dependent upon an inertia parameter and the type of adaption, linear or asymptotic, with regards to the instantaneous adaption of consumption. The inertia parameter set up a restriction such that the consumption will adapt gradually instead of instantaneous. The adjustments are based on the price of electricity and price at the given step, the disconnection price, in a week.

The total capacity of each step can be divided into three parts, inflexible inside and outside, and flexible capacity [37]. Inflexible inside is the share that is consumed in the week no matter how high the price is. Inflexible outside is the share of the capacity that is outside regardless of how low the price is, meaning that this is not consumed. Flexible capacity is the share of the total capacity that is price depended and if a price goes beyond the disconnection price this demand will be disconnected. These steps are the basis for the formulation of gradual adaption of consumption together with the prices.

The price affects the consumption in the manner that when the prices are persistently high the consumption will go towards zero while prices that are persistently low the consumption will move towards the maximum capacity. This is shown in figure 2.7 where the disconnection price is 25 øre/KWh.

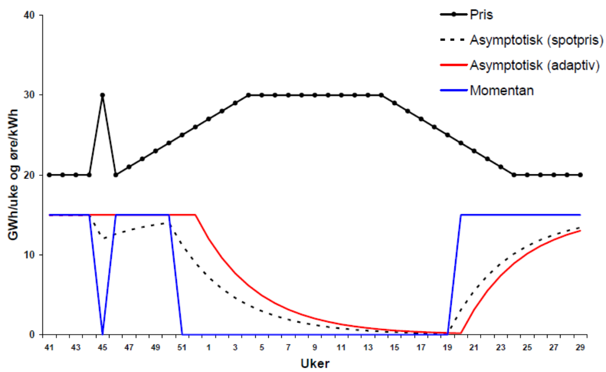

Figure 2.7: Demand profile for instantaneous, asymptotic and linear adaption [37].

Flexible loads

For all loads in the system, they can be categorized after how flexible they are. In [38] loads are divided into groups depending on their potential of flexibility. The groups indicate the priority it has, which ranges from low to high priority. The low priority groups are the ones that can offer flexibility where they can either be shifted or curtailed without interfering with the comfort of the end-users. While the high priority is loads that do not have the potential to be reduced or disconnected. Figure 2.8 illustrate the priority loads and some appliances within the group.

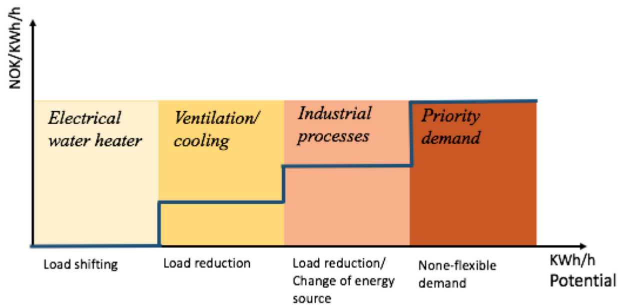

Figure 2.8: Priority loads [38].

Demand response in the Nordic system

Demand is dependent on the geographical and social-economical situation of a country. The value of flexibility will vary across regions as these situations will affect the power generation mix and what energy resources are used for heating and other appliances. In the Nordic system, this is variable as the countries have different potential.

Norway is seen as the European battery with its large share of hydropower and reservoirs as this is the main resource of flexibility. On the consumer side, electricity covers almost all the demand for heating in households. Due to the great share of reservoirs, hydropower producers handles the flexibility. There is still though a need to manage seasonal shortages and surpluses in hydrological balance [39]. Demand response in Norway has a growing degree as system services from industries are used.

Finland and Sweden have both a good share of hydropower, but not to the same extent as Norway. They have a more variable energy mix with thermal, nuclear, hydro and other renewable energy sources. Due to the difference in the geographical production side for Sweden, there is a need to manage seasonal variations in the north and manage the peak-load challenges in the south. While Finland needs flexibility to manage peak-loads and incidents. Sweden differs from Norway as they use district heating for heating buildings.

In Denmark, the electricity consumption from households and industry is lower than in the rest of the Nordic countries. This is because gas and heat are the energy resources used for heating [39]. The need for flexibility here is mainly dependent upon handling fluctuations in renewable generations since they have a large share of intermittent generation in terms of wind power and no power intensive industry.[40] states that there is 27 % flexible consumption in Denmark which suggests that the fluctuation in wind production can be handled by demand response.

Looking at the Nordic region as a whole, the frequency in the synchronous Nordic area is a regional concern. Also, the quality of frequency is challenged by intermittent generation and of new interconnectors. The Nordic TSOs need short-term flexible resources to ensure system security and quality of supply.

We see here that demand response in the Nordic system is favorable. Demand response can come from different technologies and battery storage. In [12] there is seen that battery storage for flexibility is not a good investment since the Nordic power system consists of a large extent of hydropower that is flexible. This is due to the fact that hydropower works well as a service for reserves in the balancing market as they can respond quickly to imbalances in the system compared to thermal generation. Due to the quality of frequency in the Nordic grid concerning intermittent generation, Statnett has looked into FFR, a reserve that is going to work faster then FCR that has an activation time of 1-2 secs. They found that hydropower generators do not make the cut to be actors for this reserve. Hence, there is a need to have demand response as this is a resource of flexibility that can respond fast.

The potential of demand flexibility in the Nordic has been tested. On the Danish island Bornholm, there was an ongoing project from 2011 to 2019 named EcoGrid with an extension, EcoGrid 2.0 [41, 42]. The first project aimed at activating flexibility from the demand side due to variable electricity prices while EcoGrid 2.0 created and demonstrated a market for trading flexibility from DERs [43]. In the first years, the concept of the real-time market was tested to activate small-scale DERs and demand response [41]. The pricing here was updated every five minutes to provide a dynamic response which will taking advantage of flexible electricity demand and DERs. In Ecogrid 2.0 there was developed a link between the household and the electricity market with a new actor: The aggregator. The aggregator is the one that bundles the flexibility from DERs and uses the aggregated flexibility to offer services to the system operator and balance responsible parties [43]. The result from the first project showed that there is a significant potential for demand response to be obtained and this can be activated from real-time price signals [41]. From EcoGrid 2.0 it was obtained a reduction in curtailment of wind power, an increasing share of renewable energy resources and social welfare [43].

2.3 Hydro-thermal power scheduling

Power scheduling is a vital activity when it comes to the production of power. The price that the producer forecast will impact the bidding they will do in the day-ahead market and their plans for the future. This price is for them seen as the nodal price which depends on the general market balance, the system price and transmission charges including possible congestion fees [1]. Seen from the producer point of view the generation scheduling is formulated as a given forecast of future market price where it tries to maximize the expected profit over the planning period [1].

The Nordic system is a hydro-thermal power system due to its large share of hydropower [36]. The Nordic countries use power scheduling models based on hydro-thermal scheduling due to the interconnection between bidding areas and their strong exchange capacity with other areas. For models developed for the Norwegian and the Nordic system, it is vital to include the inflow and water values as these are parameters that influence future prices. This is essential for optimal utilization of hydropower which establishes a demand to model future price behavior under different assumptions [36].

In figure 2.9 there are several stages of scheduling presented as to forecast the future market price. Their time horizon and how detailed they forecast separates them. Below they will be presented.

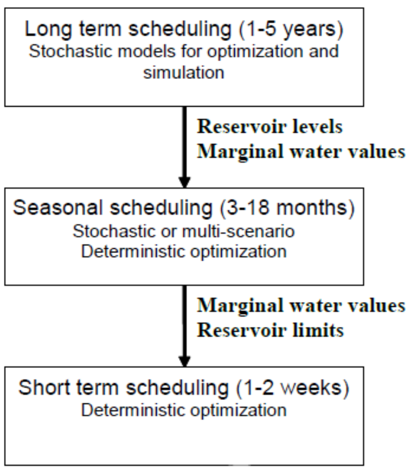

Figure 2.9: Scheduling hierarchy [36]

Long-term scheduling

The aim of the long-term scheduling, with a time horizon of one to five years, is to obtain the optimal use of resources [36]. Stochastic dynamic programming is used where both the inflow and price are stochastic variables [1]. Input to the model is statistical data here meteorological and hydrological data [36]. Results provided by the long term models are often used for boundaries for both seasonal and short-term models [44].

Long term scheduling models can both be model at global and local levels. The global level is formulated for the whole Nordic system where it can capture changes in interconnection capacities, changes in demand and commissioning of new generations, and use this for analysis purposes. From the global analysis, it can obtain the system price from the model simulations. Local analysis, on the other hand, provides future prices from statistical descriptions. This is because the producer is focusing on their own system. EMPS is a type of global analysis which is a set of parallel EOPS modules where there are possibilities for power exchange between areas. EOPS is one area power scheduling model where the simulation part takes into account different scenarios for inflows into the reservoir and is seen as a model on the local level [1].

EMPS is the model that is often used in planning and forecasting the power system with a considerable share of hydropower. This is due to its utilization of transmission lines and cables, the possibility to capture the whole system and changes that will affect the investments for one area depending on the situation in other areas in the future [45]. It wants to minimize the expected cost over the system subject to all constraints [44]. There are two steps to solve EMPS. The first step is the strategy part. Here it aims to find the best solution for the use of water. It uses stochastic programming and heuristic approaches to handle the interconnection between areas. The second step is the simulation part which is a market clearing process. The water values found in the strategy part is used here. The model is using aggregated reservoirs because of the uncertainty that has to be added to long-term models [36].

EMPS was in the 1980s developed and has throughout been adjusted with more constraints and new analysis purposes. The simulation capability has been enhanced in the last decades, but are not equally handled in the strategy part. Where it has left a growing gap between the system description seen in the simulation and strategy parts. This can have a consequence of having too many simplifications, and the process of model calibration may become more complex and less transparent [14]. The increasing share of renewable energy resources in the system has made the value of models with a greater insight into short-term variability important to handled [44]. SINTEF Energy Research has developed a new long term model for optimization and simulation of hydro-thermal power with a detailed description of all relevant constraints, including constraints given by individual hydro storages and plants using a formal optimization method [46]. The model developed simulates a sequence of problems referred to as scenario fan problem [44]. The model is well known under the name FanSi and differs from EMPS where it does not aggregate the reservoirs as this is modeled with more details.

Seasonal scheduling

Seasonal scheduling is a stochastic or multi-scenario model that uses deterministic optimization. The time horizon is between 3 to 18 months [36]. It connects the long and short term models since the short term model requires detailed information about each reservoir while the long term uses an aggregation of the reservoirs. The model is based on the same physical description of the system as the long term models. It differentiates in the mathematical methods where it allows for a better valuation of the water in each reservoir [36].

This type of scheduling is used for seasonally times as when there are changes between seasons. One model used is ProdRisk which is developed by SINTEF Energy Research.

Short-term scheduling

Short-term scheduling is a deterministic model that aims at optimizing the balance between demand and supply in the near future while adapting to the long-term strategies for system operation [1]. It allocates the actual operation of the resources and the time horizon is from one to two weeks. The difference between the seasonal and long-term models is that it needs a higher degree of detail that is adapted to the actual decision since the analysis results in the actual operation plan [36].

Scenario analysis might be necessary for the model even though the model is deterministic as to consider the solution space. The reason is that a few scenarios deviate from the standard. Some scenarios as extreme cold days and rain fronts that are uncertain where and when it will happen will create uncertainty [36].

Since the seasonal model has a less detailed description and a longer time horizon then the short-term model, there are set up requirements to the short-term model. It has to be flexible, adapt to inaccuracies induced by variations in assumptions, and model detail in both models [36].

A model that has been used in the Nordic system is SHOP (Short-term Hydro Operation Planning) which schedule hydropower to ensure the available resources are optimally utilized [47]. It also exploits the options of selling and buying within the spot market, while fulfilling firm load obligations, to maximize the profit. A new short-term model under the name PriMod is developed and will be further presented in chapter 3.

Demand response in hydropower scheduling

Demand response in a hydropower system is not thoroughly researched since the hydropower generation works well in a situation where ramping is needed with fast responsive turbines and the use of pumped storage hydropower. With the increasing share of VER, the need for balancing services are higher. Demand response in the hydropower scheduling is needed to modeled better since to account for the real benefits of DR, market models have to be model accurately [31] and also to get a better balance in the system.

It is favorable to schedule power thoroughly as well as having VER to reduce the cost in the system [48]. In [19] and [49], the non-power constraints in the operation of hydropower is said to limit the increasing share of VER. Therefore the modeling needs to be developed in an accurate approach. [19] presents a bridge between the gap of the hydro system's constraints and the potential for improvement of the electricity production modeling such that the impacts of variable generation can be more accurately captured. The approach is based on the two models, PLEXOS and RiverWare. PLEXOS is a production cost model that models the unit commitment and dispatch of generators in the power system. It seeks to minimize the overall cost of operating the system. RiverWare is a hydro modeling system that is designed to optimize the multiple goals associated with multi-purpose reservoirs. From the combination through a demonstration case, there was an overall reduction in production cost and variable generation curtailment as the effect of modeling hydropower more detailed. Demand response is here said to decrease the price even further when present. With a more detailed model, demand response can work as a barrier to respond to imbalance close to the operation time as it has a faster activation time than hydropower generation. The cost associated with generator start and stop cost can decrease with the implementation of demand response [48] as it is more cost-effective to dispatch demand response instead of starting and stopping units [19], suggesting that when modeling demand response well in the hydro-thermal power scheduling there is potential for lower the cost as demand response adjust the demand due to price or curtailment when needed.

Chapter 3

PriMod - a short-term hydro-thermal market model

PriMod is a deterministic model developed by SINTEF Energy Research through the project PRIBAS - Price Balancing Services in the future Nordic Power Market. The project was carried out because the power generation and markets structures are changing and the call for balancing services were crucial due to increase of intermittent energy. The model constructed is a short-term hydro-thermal market model. It has a finer time resolution then other models used, as SHOP, where it uses 15 minutes instead of 1 hour. PriMod is a complex model as it uses both a long-term and short-term model which differentiates itself from other models. It consists of two modeling layers, strategic and operational. We will here present the object of the two layers and how to optimize the model.

3.1 The strategic model

The strategic modeling layer is solving the long-term hydro-thermal scheduling problem [20]. The choice of a long-term model could be any model, but the choice fell on the FanSi model because the problem to be solved is stochastic due to uncertainties in the future related to exogenous power price and weather, but most important FanSi does not aggregate the reservoirs for each area. EMPS, the model that has been heavily used towards hydropower scheduling, was not chosen since it aggregates the reservoirs for each area making the market lack details of the water values.

FanSi is a model known as a scenario fan simulator (SFS) which solves a scenario fan problem in each time stage [46]. The simulator optimizes sequences of decisions by solving scenario fan problems (SFP) along with all scenarios in consecutive order [50]. The solution is passed on from the first-stage decision to the next time stage. SFP is a two-stage stochastic linear programming problem. The first stage is based on a given week with a given realization of stochastic variables [46, 50]. While the second stage consists of several scenarios where each decision sets the end-value coupling for the first stage provided by Benders cuts [50].

From the strategic model, the output obtained is the Benders cuts. It represents the expected marginal values of water in the hydro reservoirs, known as the water value. This is used as the end-of-horizon valuation of water in the operational model [20]. Figure 3.1 illustrates the coupling between the two modeling layers. Here, the operational model uses the same data as the strategic model for each week when solved. At the end of the week, water value is evaluated according to the Benders cut obtained from the strategic model. The results are stored and the reservoir level is passed on to the next week. The water value is evaluated for each week to see that the use of resources is allocated optimal and within boundaries.

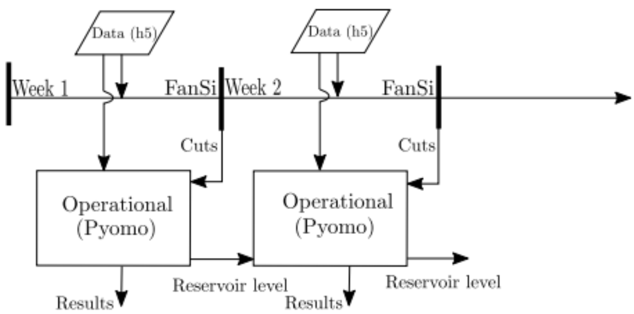

Figure 3.1: Strategic and operational model coupling [20]

FanSi will give a more insightful overview of the hydropower on a broader level as we can see the situation clear on some specific regions/areas. Since we do not aggregate the reservoirs this will cause an increase of computation time compared to EMPS. To handled this computation time there has been looked into a new extension of EMPS, EMPS-W. This extension is said to allow more consistent treatment of detailed hydrological constraints and in turn more precise valuation of hydropower flexibility [14].

3.2 The operational model

The operational model is the short-term problem that re-optimize the weekly decision problem with more details on a finer time resolution [20]. It is refined by adding detailed constraints on the operation of thermal power plants [11]. The system data used in the model for each week is the same as for FanSi. The output from the strategic model, here the Benders cut, is used for evaluating the value of water at the end of the week as seen in figure 3.1. The operational model is solved each day within the week which means that the operational model is solved seven times and then the reservoir storage level is passed on to the next week.

To model the operational model, the programming language Python is used which is an open-source language. Pyomo is a package used to optimize the model. CPLEX is set as the solver.

Some of the restrictions are presented below. These restrictions are directly affecting the loads. It is also crucial to mention that all the restrictions created in the optimization model will impact the objective function and contribute to set the final price. Other restrictions implemented in PriMod that are not presented are reservoir balance, release balance, ramping and start/stop costs of thermal production, and Benders cuts constraining expected future cost as some to mention. Nomenclature for the restrictions below is found at the beginning of this thesis under section Nomenclature.

Objective function
The objective function of power scheduling is to obtain the highest social welfare cost. Leading to maximize the profit, which leads to minimizing the production cost. The restriction is focusing on not misuse water in the hydro-thermal power.

$$\begin{aligned} Min \quad & \sum_{k\in\mathcal{K}_t}\sum_{n\in\mathcal{M}_a}\sum_{a\in\mathcal{A}}\Big(\mathcal{M}^{price}_{n,k} m_{n,k} \\ & + \sum_{r\in\mathcal{R}_a}(q^{bypass}_{r,k}\mathcal{P}^{bypass} + q^{spill}_{r,k}\mathcal{P}^{spill} + q^{tank}_{r,k}\mathcal{P}^{tank})\Big) + \alpha \end{aligned} \tag{3.1}$$

Power balance for areas with hydro generation
The power balance is setting a restriction that the power generated in each area must be equal to the demand. The power balance for hydro generation is taking into account the transmission between areas here export and import to cover the

residual load while accounting for pumped and generated power from hydro.

$$\begin{aligned}\mathcal{L}_{a,k} - \mathcal{W}_{a,k} = \sum_{r \in \mathcal{R}_a} \Big(\sum_{p \in \mathcal{S}_r^{PQ}} (\eta_{r,p}^{PQ} q_{r,p,k}^{dis} \mathcal{H}_r^{h/h_0}) - \mathcal{Q}_r^{pump} q_{r,k}^{pump} \Big) \\ + \sum_{n \in \mathcal{M}_a} m_{n,k} - \sum_{i \in \mathcal{A}} (t_{i,j,k} - t_{j,i,k}(1 - \mathcal{T}_{j,i}^{loss}))\end{aligned} \tag{3.2}$$

Power balance for areas with thermal generation
The power balance for a thermal generation is the same as the power balance for hydro generation, but does not take into account hydropower generation.

$$\mathcal{L}_{a,k} - \mathcal{W}_{a,k} = \sum_{n \in \mathcal{M}_a} m_{n,k} - \sum_{i \in \mathcal{A}} (t_{i,j,k} - t_{j,i,k}(1 - \mathcal{T}_{j,i}^{loss})) \tag{3.3}$$

3.3 Pricing

The price is vital for the production side to plan their production and how they are going to bid in the day-ahead market. An incentive for how an end-user consumes energy comes from the price in the market which further impacts the potential for price-based demand response.

The price obtained from PriMod is calculated in a different approach compared to the day-ahead market where they find where the supply and demand curve is intersected. PriMod is rather solving a dual problem from the power balance equations 3.2 and 3.3. From this, it is constructed a marginal price which means that the price indicates the benefit of producing one more unit of goods where goods here are power (MW).

Chapter 4

Modeling Demand Response

In this chapter, there will be presented restrictions to PriMod to capture the impact of price-based demand response in the system. First, gradual adaption is presented which is based on the paper [37] and formulated due to indirect control as one of the resources for demand response. The next method is demand side management that can be used in the system. There will be used load models that focus on curtailable and shiftable loads that will cover low to medium priority demand that uses direct control of load shifting and peak clipping. The equations formulated have been developed through theory and insight of how the load shifting works at a lower level from the INVADE project [51] and [52] as to account for compensation for the decreased comfort for the end-user due to DSM.

4.1 Gradual adaption of consumption

Gradual adaption of consumption is based on the research paper [37]. Here it was presented two methods, asymptotic and linear approach to account for the adaption. In this thesis, the focus will be on the linear approach and the equations formulated below are based on the equations found in [37] that show the change in consumption as a result of high and low prices. The equations have previously been formulated under the specialization project *Modelling demand response in a short-term hydro-thermal model* written in the spring semester of 2019.

First there is presented gradual adaption for the market steps, $\mathcal{M}_a$. These equations are only valid when $m^{cap}_{n,k}$ is negative since this indicates that it is a demand step.

$$m_{n,k} = m_{n,k'} + (1 - 2z)(1 - \beta_{a,k})m_{n,k}^{cap} \tag{4.1}$$

$$z \in \{0, 1\} \quad | \quad 1 = \mathcal{M}_{n,k'}^{price} > \mathcal{P}_{a,k'} \; and \; 0 = \mathcal{M}_{n,k'}^{price} \leq \mathcal{P}_{a,k'} \tag{4.2}$$

$$0 \leq m_{n,k} \leq m_{n,k}^{cap} \tag{4.3}$$

Equation 4.1 is constructed such that it adjust the consumption on the market step, $m_{n,k}$, in time period k. It is equal to the consumption from the same time step last week, time step k', plus the difference due to high and low prices. The binary variable z is set by equation 4.2 and will account for whether the area price,$\mathcal{P}_{a,k'}$, is higher or lower than the market step price, $\mathcal{M}_{n,k'}^{price}$, last week. It is set to 1 when the market step price last week, $\mathcal{M}_{n,k'}^{price}$ is greater than the area price, $\mathcal{P}_{a,k'}$. The binary variable will impact the consumption as whether it will increase or decrease towards its limits. The amount of the consumption that is adjusted is set by $(1 - \beta_{a,k})m_{n,k}^{cap}$. Here the total capacity on the step is adjusted towards the inertia parameter, $\beta_{a,k}$. It has a value between 0 and 1 depending on how fast consumers respond to the price. Equation 4.3 make sure that the consumption is non-negative and does not exceed the capacity of the step.

Since we are accounting for flexible firm demand, gradual adaption of consumption will also happen on the price-elastic share of the firm demand. For each step within the flexible firm demand market steps, $\mathcal{F}_a$, they are handled in the same approach as the market steps above. Here $y_{s,k}$ indicates the consumption on the flexible firm demand market step and $\mathcal{C}_{s,k'}^{price}$ is the cost at that step last week, k'. Since consumption on the flexible firm demand steps has positive values, equation 4.5 has opposite value for the binary variable compared to equation 4.2.

$$y_{s,k} = y_{s,k'} + (1 - 2z)(1 - \beta_{a,k})y_{s,k}^{cap} \tag{4.4}$$

$$z \in \{0, 1\} \quad | \quad 0 = \mathcal{C}_{s,k'}^{price} > \mathcal{P}_{a,k'} \; and \; 1 = \mathcal{C}_{s,k'}^{price} \leq \mathcal{P}_{a,k'} \tag{4.5}$$

$$0 \leq y_{s,k} \leq y_{s,k}^{cap} \tag{4.6}$$

There will be a change in the total firm demand since we are adjusting the price elastic share of the firm demand. The new total firm demand, $\mathcal{L}_{a,k}^{new}$, that will replace the load, $\mathcal{L}_{a,k}$, in equation 3.2 and 3.3, is presented below.

$$\mathcal{L}_{a,k}^{new} = \mathcal{D}_{a,k} + \sum_{s \in \mathcal{F}_a} y_{s,k} \tag{4.7}$$

Here the inelastic firm demand, $\mathcal{D}_{a,k}$, is calculated as a share of the firm demand set by $\delta_{a,k}$.

$$\mathcal{D}_{a,k} = \mathcal{L}_{a,k}(1 - \delta_{a,k}) \tag{4.8}$$

The gradual adaption of consumption formulated is solved before PriMod is solved for each day. The input is the price and consumption from last week and the result, consumption on the market steps, obtained is then used in PriMod as shown in figure 4.3.

4.2 Demand side management

An own optimization problem is constructed for shifting and curtailment of loads over a day. The flow of the development to incorporate DSM is shown in figure 4.1. Here the model developed is solved after PriMod is solved for each day. The input to this optimization model, here shown as DR optimization, is the loads that can be shifted and curtailed, $W^s_{a,t}$ and $W^c_{a,t}$, and the area price for each time step throughout that day, provided from PriMod. After the optimization model is solved, PriMod is yet again solved for that given day and a new firm load has been given as an input, provided by the DR optimization model (equation 4.17). This procedure is done each day within all weeks.

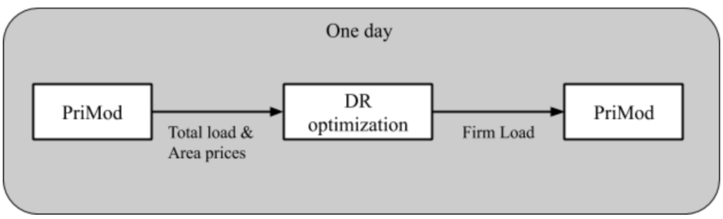

Figure 4.1: Flow chart of demand side management.

The objective function, equation 4.9, aim to minimize the cost of demand. There has been added a compensation cost, $\mathcal{C}^{comp,s}_{a,t}$, to the difference between the load, $W^s_{a,t}$, that was given as input and the scheduled load, $\omega_{a,t}$. This is done for both the load shifting and curtailment ($W^c_{a,t}$ and $\chi_{a,t}$) to compensation the end-user for loss of comfort due to DSM.

$$\begin{aligned} Min \quad & \sum_{t\in T}\sum_{a\in A}\Big(\mathcal{P}_{a,t}(\chi_{a,t}+\omega_{a,t}) + \mathcal{C}^{comp,c}_{a,t}(W^c_{a,t}-\chi_{a,t}) \\ & \qquad + \mathcal{C}^{comp,s}_{a,t}(|W^s_{a,t}-\omega_{a,t}|)\Big) \end{aligned} \tag{4.9}$$

s.t.

$$\sum_{t\in T}\omega_{a,t} = \sum_{t\in T} W^s_{a,t} \quad \forall a\in A \tag{4.10}$$

$$\omega_{a,t} \leq W^s_{a,t} \quad \forall a\in A, t\in T^s \tag{4.11}$$

$$\omega_{a,t} \geq W^s_{a,t} \quad \forall a\in A, t\in T : \{T\notin T^s\} \tag{4.12}$$

$$\chi_{a,t} \leq W^c_{a,t} \quad \forall a\in A, t\in T^c \tag{4.13}$$

$$\chi_{a,t} = W^c_{a,t} \quad \forall a\in A, t\in T : \{T\notin T^c\} \tag{4.14}$$

$$W^{min} \leq \omega_{a,t} \leq W^{peak} \quad \forall a\in A, t\in T \tag{4.15}$$

$$\chi_{a,t} \geq W^{min} \quad \forall a\in A, t\in T \tag{4.16}$$

Equation 4.10 to 4.12 taken care of the shiftable loads. They make sure that the total amount of load is the same during the day and handles that the loads are allocated right in terms of its potential given its time step. Equation 4.13 and 4.14 handled the curtailable demand. It states that the loads can only have the same or reduce demand within the time step.

Equation 4.16 and 4.15 are handling the upper and lower limits of how much load that can be adjusted within each time step. It makes sure the peak demand, W^{peak}, is not exceeded and sets a lower boundary to avoid the rebound effect. We have here set W^{min} to 95% of the off-peak demand (lowest demand that day).

When the optimization has been done for that day the inelastic firm demand is adjusted. The new inelastic firm demand,$\mathcal{D}^{new}_{a,t}$, is used as input to PriMod when it is solved again.

$$\mathcal{D}^{new}_{a,t} = \mathcal{D}_{a,t} - (W^c_{a,t}-\chi_{a,t}) - (W^s_{a,t}-\omega_{a,t}) \tag{4.17}$$

4.3 Implementation

Here it will be presented how to implement gradual adaption of consumption, and load shifting and curtailment to PriMod. PriMod is solved each day within the week. For each week the Benders cut and the reservoir levels is updated. To implement the demand response we are to make some adjustments for how to optimize the model as the demand response is dependent on the price for the week before or the day that is optimized.

Figure 4.2 illustrate the flowchart for a set of weeks where within each week there is an optimization model that is solved. The results from the model are used as input to the next week.

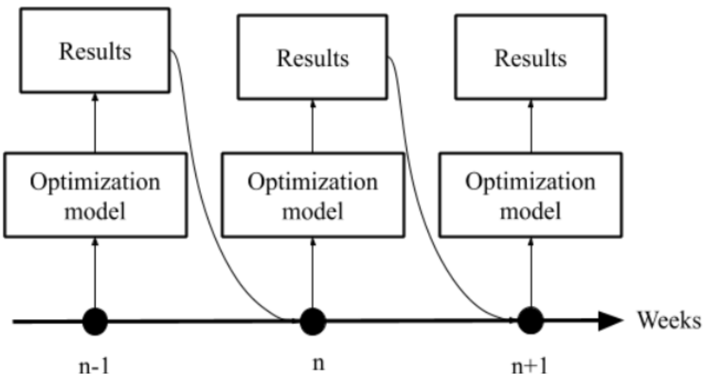

Figure 4.2: Flowchart for the weekly optimization for price-based demand response.

Figure 4.3 illustrates the optimization model for one week. The grey box indicates one day and is solved seven times each week to account for all days within that week. Each day gradual adaption of consumption is handled before PriMod is solved. Meaning that the market steps, $m_{n,k}$ and $y_{s,k}$, will be parameters in PriMod instead of variables. The gradual adaption of consumption is calculated from the price and consumption last week, week n-1. Implying that when a week is solved, the price and consumption on each step on the preferance curve are sent to the next week to account for gradual adaption of consumption. Since it is assumed that the consumption is adjusted due to price and consumption from last week as the consumption and price in week n-1, day j, hour x will impact week n, day j, hour x. What happens is that each day the optimization model accesses the result from the previous week and uses this to adjust the consumption on the price-elastic demand and the flexible firm demand. When obtaining the consumption this is given as an input to PriMod. PriMod is first solved one time where it calculates the prices and demand. Since the load shifting and curtailment are dependent upon the price that given day there is an own DR optimization model created. It handles the load shifting and curtailment. The output here is a change in demand and used to subtract it from the firm demand. It will create a shift in the demand curve to the right or left, depending on whether the firm demand has increased or decreased. When the optimization of DR is solved, PriMod is again solved for that given day now with a new firm demand, adjusted due to the output of the DR optimization. The result obtained for each day is stored for use in the next week.

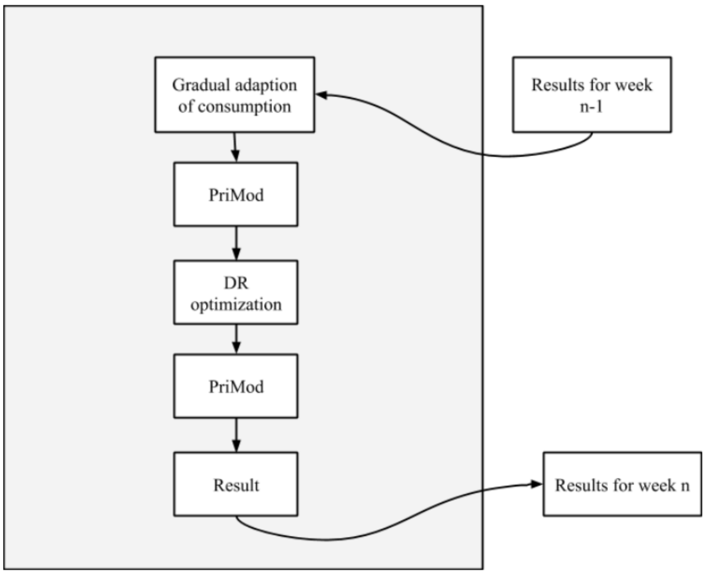

Figure 4.3: Flowchart for the optimization model of price-based demand response.

4.4 Data

The data used in the PriMod script is given by SINTEF Energy. The data set is a simplified representation of the Nordic system. There are four areas where three are hydropower areas. While the last area is modeled as a thermal area and illustrates the southern part of Europe, but we assume it will represent Denmark in this case. The four areas are Numedal, Otra, TEV (Trondheim Energi Verk) and Term. The latter one is the one that indicates the thermal area and is the connection towards Europe as here there is more thermal production. The interconnector between the areas is shown in figure 4.4.

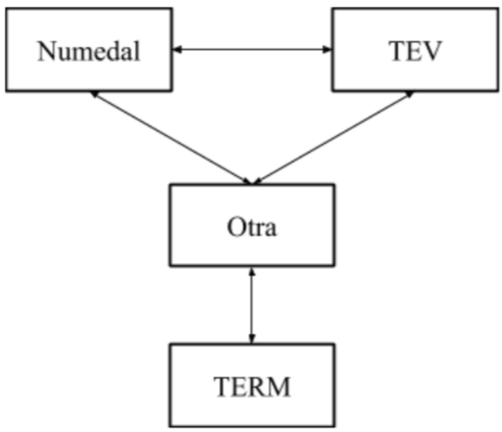

Figure 4.4: Connection between areas in data set.

The firm demand given in the data set for a week is shown in figure 4.5. It shows the demand within a week and indicates the total demand since the demand is close to inelastic.

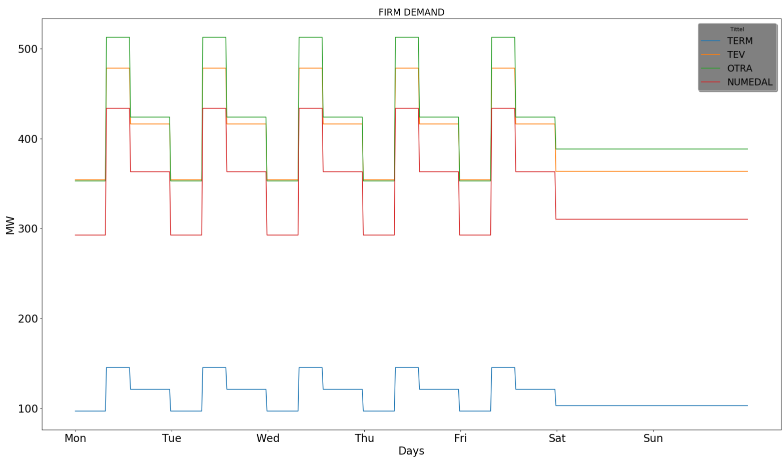

Figure 4.5: Firm demand that is given in the data for a week.

The inertia parameter, in gradual adaption of consumption, needs to be chosen. Since it set up a restriction such that the consumption will adapt gradually instead of instantaneous the choice fell on 0.80 for all areas and time steps. The reason is that the consumer does not react to the prices immediately and we want to add more slowness to it compared to an inertia parameter of 0.95. This is based on that consumer still does not react immediately since the knowledge of AMS is still moderate and also the use of smart systems has not yet been thoroughly integrated.

The cost of each step on the flexible firm demand curve has been chosen on the basis that the highest price on the price-elastic curve for demand was found to be a right below 25 mu/MWh. Table 4.1 presents the cost and there are 10 steps that are accounted for.

$n \in \mathcal{F}_a$	$C_{n,k}^{price}$
1	300
2	270
3	240
4	210
5	180
6	150
7	120
8	90
9	60
10	25

Table 4.1: Cost for flexible firm demand.

As of loss of comfort for introducing DSM into the grid there are a need to compensate the consumers. The compensation cost for shifting and curtailing loads are given as 10 Euro/MWh in [52], but since this unit does not match with PriMod, it will be adjust. The adjustment is focused on that we have found that the peak price found in PriMod is 30 mu/MWh which is about 50% of the peak demand when accounting for peak price for the unit Euro/MWh. Then we can assume a compensation cost of 5 mu/MWh.

Area	$C_{a,t}^{comp,s}$	$C_{a,t}^{comp,c}$
Numedal	5	5
Otra	5	5
TEV	5	5
TERM	5	5

Table 4.2: Compensation cost for each area in mu/MWh.

To handle the flexible loads there are need of assumptions for how much of the demand is flexible. In [53, 54] there is said that there are 64% space heating and 15% electrical water heaters which is the base for choosing loads that can be shifted or curtailed. The amount of energy consumption that is from residential sector is 27%. This will account for an amount of 17% space heating and 4% water heaters[54]. In [55] there is said that in Denmark 65% of citizens use district heating as the energy source for heating. We can then assume that space heating is decreasing in the thermal area to 6%. For all percentages there are add on a percentage of 5% since we want to add some potential from the power intensive industry and commercial sector. The choices for the percentage is presented in table 4.3.

Area	Percentage curtailable	Percentage shiftable
Numedal	23	9
Otra	23	9
TEV	23	9
TERM	11	9

Table 4.3: Percentage shiftable and curtailable for each area.

In a hydro-thermal power scheduling model, the reservoir level is important for the water value. The chosen reservoir levels are presented in table 4.4 and are chosen from the median level for that given week.

Week	Reservoir level of maximum
1 (winter)	68.5%
14 (spring)	34.9%
27 (summer)	70.7%
43 (fall)	85.2%

Table 4.4: The median of the reservoir level for the given week [56].

Chapter 5

Case studies

In this chapter, there will be performed three different cases. Seasonal variations, differences in reservoir level and different percentages of flexible loads where the only load shifting is activated, are the cases that will be performed.

PriMod is the model used for solving the cases. The script implemented for the restrictions concerning DR and the original script for PriMod is found on Bitbucket upon request from SINTEF Energy Research.

When solving PriMod the restriction concerning reserves are deactivated. For the demand response restrictions, the load for the DSM is aggregated and the DR optimization model is solved to minimize the total system cost. When solving the cases, PriMod is solved five weeks at a time. Only the four last week is presented since the first week does not give a good representation of the price or demand since the Benders cuts have not been updated in the first week.

5.1 Seasonal variations

For the case of seasonal variations, PriMod is solved for the four seasons within the year. It will compare each season with each other to observe the impact and potential of price-based demand response. The results will then be compared to the base case. The base case is PriMod solved without DR and the restriction regarding reserves is chosen to be deactivated.

For each season, area and system price and demand are presented in figures and tables. The tables presented show the differences in peak demand in the areas, differences in demand and price for each area and also the difference in system demand and price.

Results

Winter

Winter is the season with the highest demand. This will lead to a high price in the system and area since the supply has to balance out the demand. In figure 5.1 the demand for each area is plotted. In all areas, the demand has decreased as a result of price-based demand response. Table 5.1 show that the greatest potential for demand response lays in the hydropower areas as the peak demand has decreased with up to 9%. From the data provided the thermal area has a lower percentage of flexible loads. This will restrict the potential of demand response, but it still has a decrease in the peak demand with 3.33%. For all weeks for each area, the change in peak demand is the same. The change of peak demand has lead the area price to decrease as seen in figure 5.2 and table 5.2. There can also be seen that the price in TERM is higher than the hydropower areas. This might indicate that the production cost is higher in TERM leading to a higher price and making an incentive for import of power from hydropower areas.

Week	Numedal	Otra	TEV	TERM
2	8.43	8.22	9.02	3.33
3	8.43	8.22	9.02	3.31
4	8.43	8.22	9.02	3.33
5	8.43	8.22	9.02	3.33
Total	8.43	8.22	9.02	3.33

Table 5.1: Peak demand change in percentage in winter.

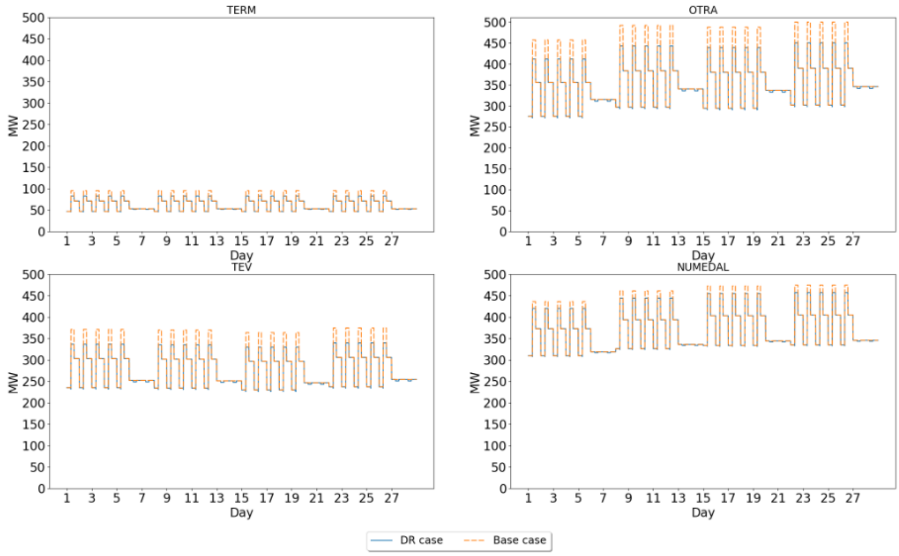

Figure 5.1: Change in demand in each area due to demand response in the winter.

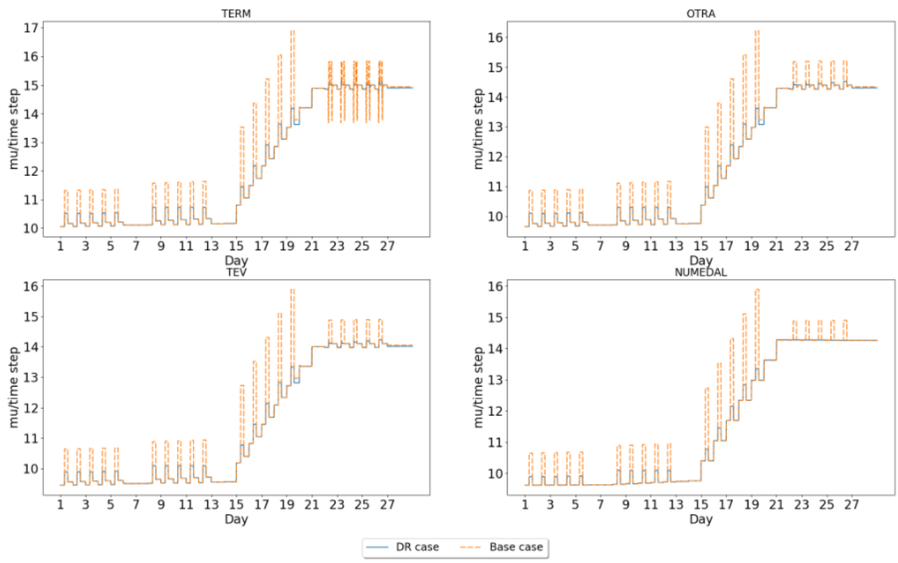

Figure 5.2: Change in price in each area due to demand response in the winter.

From table 5.2 we see that the difference in demand is stable over the areas and weeks similar to the peak demand change table 5.1. This is because of the load pattern over the week as shown in figure 5.1. The price, on the other hand, varies from week to week and area to area. The optimization model of DR wants to minimize the cost and has only imposed curtailment as this is the cheapest technology. It tries to set the price for those hours equal to the compensation cost. Due to restrictions 4.15 and 4.16 that set a maximum and minimum capacity of the demand, the demand will be restricted causing the decreasing factor for the price stop before it gets equal to the compensation cost. Meaning that the resources in the restriction is full and can not exceed anymore even though the price could decrease since there is still potential left. Also, the demand in PriMod is seen as almost inelastic and it does not have any elasticity to it. This implies that the price and demand are the same over a longer time horizon, but the price will vary. The reason being that the price is a variable affected by parameters like demand, water value and reservoir level making it variable over weeks such that the change in system and area price will be variable.

	Demand change [%]				Price change [%]			
Week	Numedal	Otra	TEV	TERM	Numedal	Otra	TEV	TERM
2	2.00	1.93	2.16	0.75	1.41	1.41	1.41	1.39
3	2.00	1.93	2.16	0.76	1.50	1.50	1.50	1.48
4	2.00	1.93	2.16	0.76	3.18	3.18	3.18	3.03
5	2.00	1.93	2.16	0.76	0.09	0.97	0.94	0.75
Total	2.00	1.93	2.16	0.76	1.55	1.77	1.76	1.66

Table 5.2: Change in demand and price in each area in the winter.

In figure 5.3 the changes in demand due to load shifting and curtailment are illustrated. The load shifting has not been activated with any demand since the price difference between the off-peak and peak hours is not greater than the compensation cost. Activating load shifting the resulting cost contains both the electricity and the compensation cost. Curtailment, on the other hand, is removing the electricity costs and is left with the compensation cost. This means that the total cost of curtailment is lower than load shifting and is more cost-effective. Hence curtailment is then the favorable technology. Load shifting is not either activated in any of the other seasons, see appendix section shifting and curtailment for illustrations.

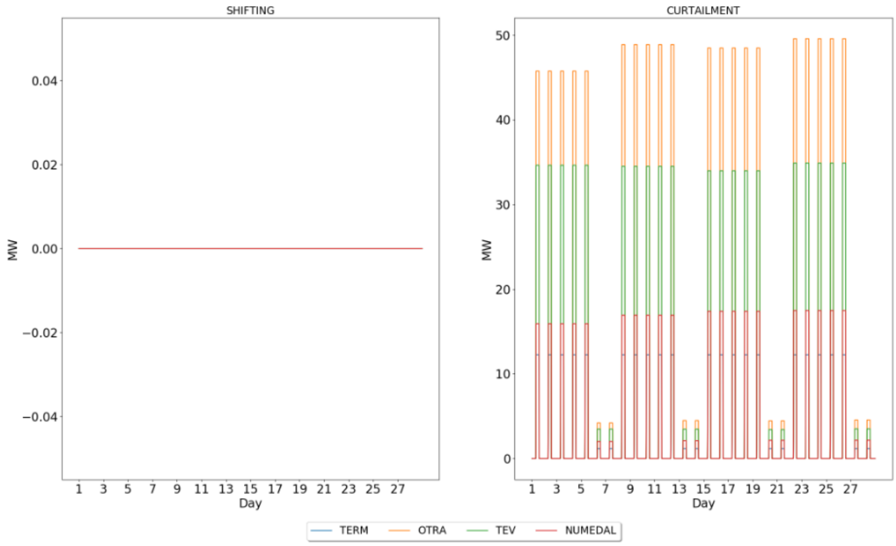

Figure 5.3: Change in demand due to load shifting and curtailment in the winter.

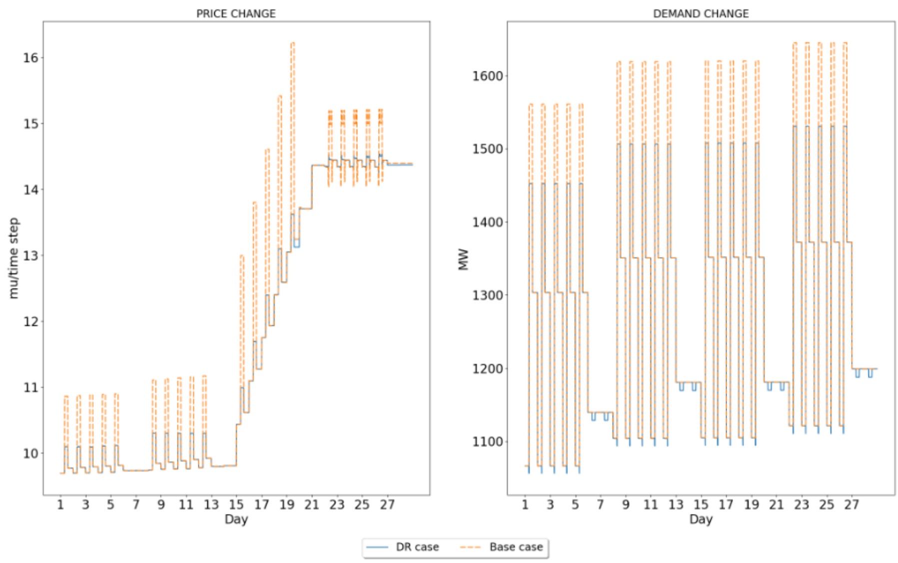

Figure 5.4: Changes in the system price and demand due to demand response in the winter.

Week	Demand change [%]	Price change [%]
2	1.63	1.41
3	1.63	1.49
4	1.62	3.14
5	1.63	0.68
Total	1.63	1.68

Table 5.3: System demand and price changes in the winter due to DR.

From figure 5.4 and table 5.3 there is seen that the system price increase with a steeper slope in week 4 (day 15-21) compare to the other weeks. The impact price-based demand response has on this week is that the change in price is the greatest here as the price is variable and high within that week compared to the other weeks. Implying that when there are price variations, the potential of price-based demand response can be high when it comes to decreasing the price. The total amount demand that has changed due to curtailment is close to the same for all weeks.

Spring

In table 5.4 the peak demand has decreased with 5 to 6 % in the hydropower area and the thermal area close to 3%. From figure 5.5 and 5.6 there is seen that it is a potential of price-based demand response in the spring when the prices are decreasing due to a lower water value. The low water value comes from that the snow is melting increasing the reservoir. In the spring the hydropower producers try to empty their reservoir to an effective level as they will during the summer and fall increase the reservoir level with rain. The price will be variable and shrinking within this season.

Week	Numedal	Otra	TEV	TERM
15	6.64	7.96	8.43	3.91
16	6.58	7.96	8.43	3.90
17	6.52	7.96	8.43	3.88
18	0.00	0.00	0.00	0.00
Tot	4.94	5.97	6.32	2.92

Table 5.4: Peak demand change in percentage in spring.

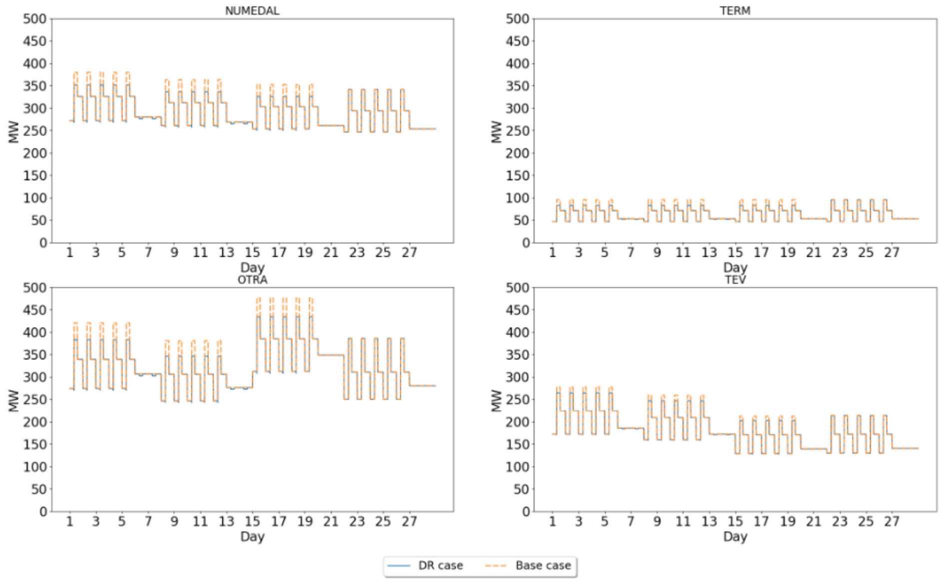

Figure 5.5: Change in demand in areas due to demand response in the spring.

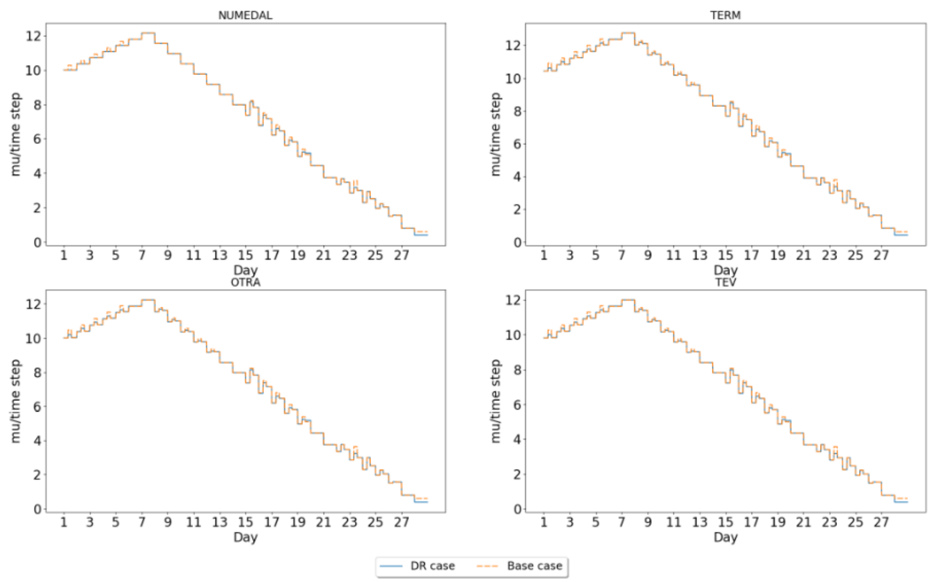

Figure 5.6: Area price changes due to demand response in the spring.

Table 5.5 shows that there is potential for price-based demand response until the price goes below the compensation cost. Demand in week 18 has not changed, but the price has. This has to do with that we have saved water and the water value has decreased creating further a lower price in the market.

	Demand change [%]				Price change [%]			
Week	Numedal	Otra	TEV	TERM	Numedal	Otra	TEV	TERM
15	1.50	0.92	2.00	1.85	0.37	0.32	0.32	0.32
16	1.48	0.92	2.00	1.85	0.05	0.21	0.21	0.21
17	1.39	0.87	1.92	1.77	0.38	0.38	0.40	0.40
18	0.00	0.00	0.00	0.00	2.23	2.23	2.21	2.21
Total	1.09	0.68	1.48	1.37	0.76	0.79	0.79	0.79

Table 5.5: Change in demand and price in each area in the spring.

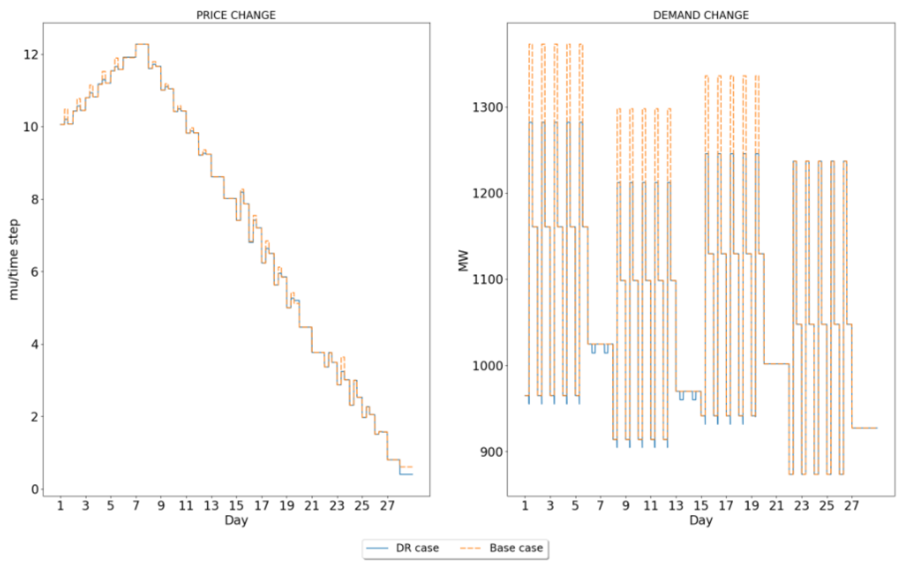

Figure 5.7: System demand and price changes due to demand response in the spring.

From table 5.6 the potential of price-based demand response in these weeks has a combined effect of decreasing the system demand with 1.14% and the system price with 0.78%. The change for each time step can be seen in figure 5.7. The changes are not big, but in the context for a grid owner the grid investment might decreases while on the residential side the saving on the electricity bill is marginal.

Week	Demand change [%]	Price change [%]
15	1.54	0.34
16	1.53	0.16
17	1.50	0.39
18	0.00	2.22
Total	1.14	0.78

Table 5.6: System demand and price changes in the spring due to DR.

Summer

From figure 5.8 and 5.9 there are no visible changes in the area demand or price. Moreover, all tables regarding areas that were presented for winter and spring are set to zero for all values. This is due to that the area prices are below the compensation cost. Though we see that the last days the price is equal or slightly above. This did not give any response in the area calculation or any visible changes in the figures.

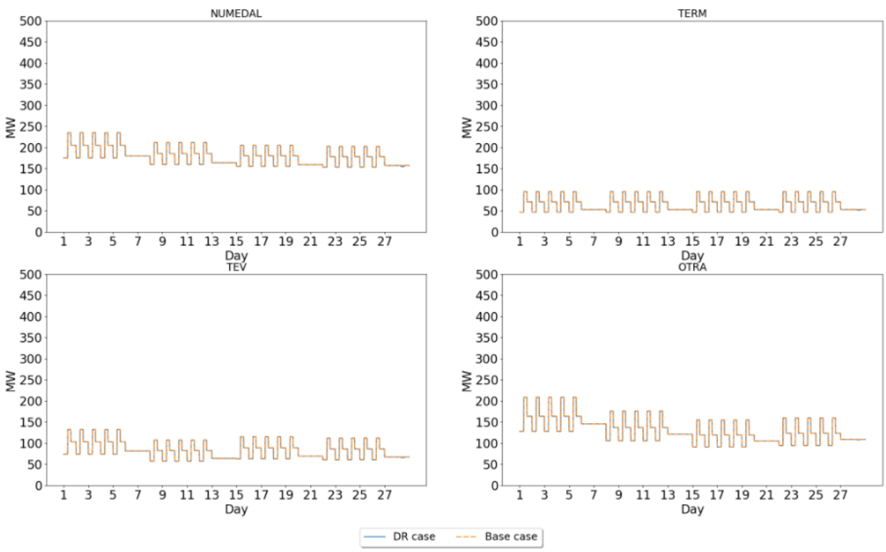

Figure 5.8: Demand change in each area in the fall due to DR.

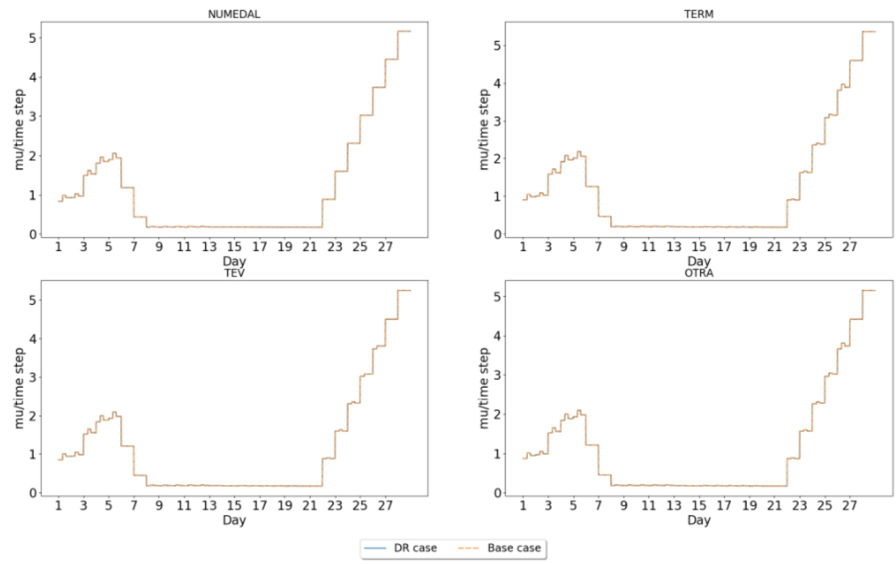

Figure 5.9: Price change in each area in the fall due to DR.

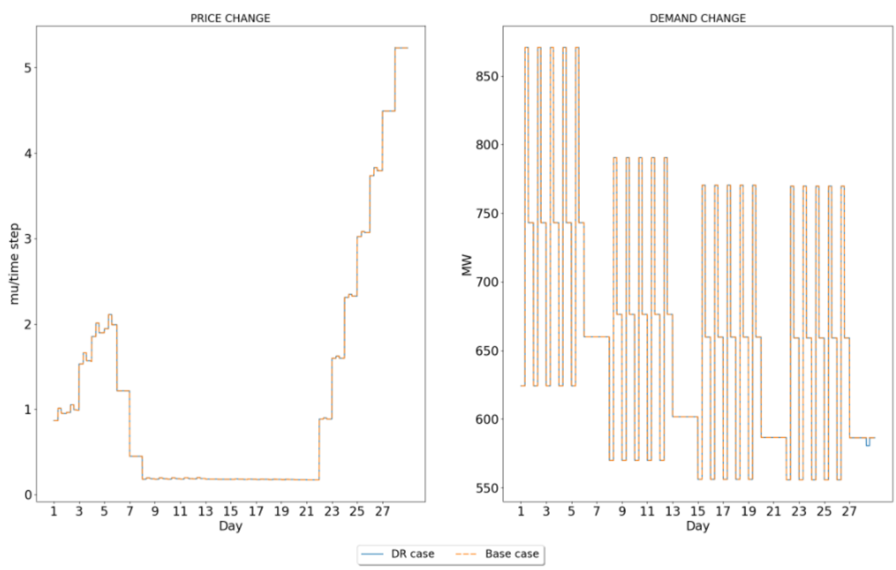

Figure 5.10: System price and demand change in the fall due to DR.

Figure 5.10 shows no visible changes in the system demand or price except for the last day in the last week. The change is marginal and presented in table 5.7. In the last days, the price is above or equal to 5 activating the demand response again. The potential of demand response in the summer is therefor seen as marginal due to low prices both in the areas and system.

Week	Demand change [%]	Price change [%]
28	0.00	0.00
29	0.00	0.00
30	0.00	0.00
31	0.03	0.00

Table 5.7: System demand and price changes in the summer due to DR.

Fall

From figure 5.11 - 5.13 there are no visible changes to the price or demand side. This is due to a compensation cost that is higher than the area and system price making it more expensive to shift or curtail demand. Hence there is no potential of demand response here as with the summer making all the tables, regarding the difference in demand and price, equal to zero. This means that the demand response in the fall has no potential since the prices are too low. Still, there might be deviations from the result since the demand modeled in PriMod is constant and has not much elasticity. Also, cases concerning extreme cold days during the fall might happen and the price might increase making price-based demand response favorable to decrease the price, but also the demand such that it can stable out the balance in the market.

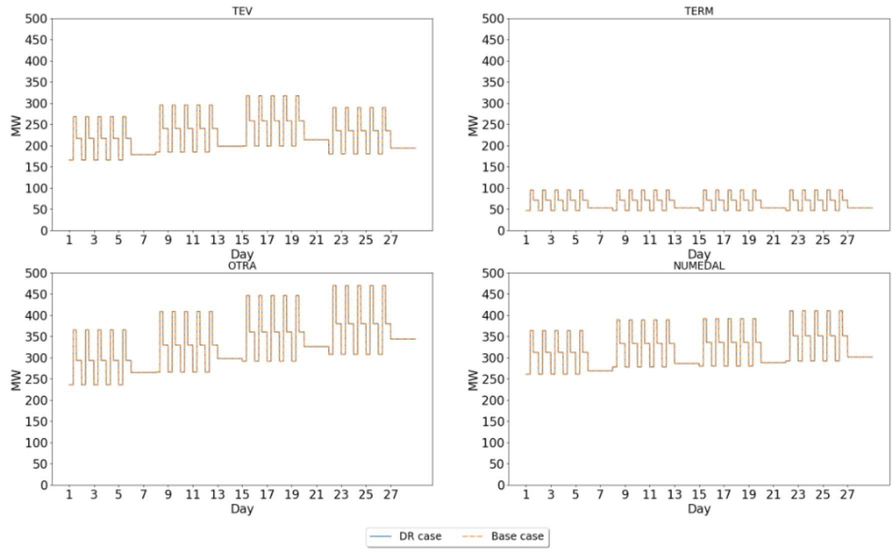

Figure 5.11: Demand change for each area in the fall due to DR.

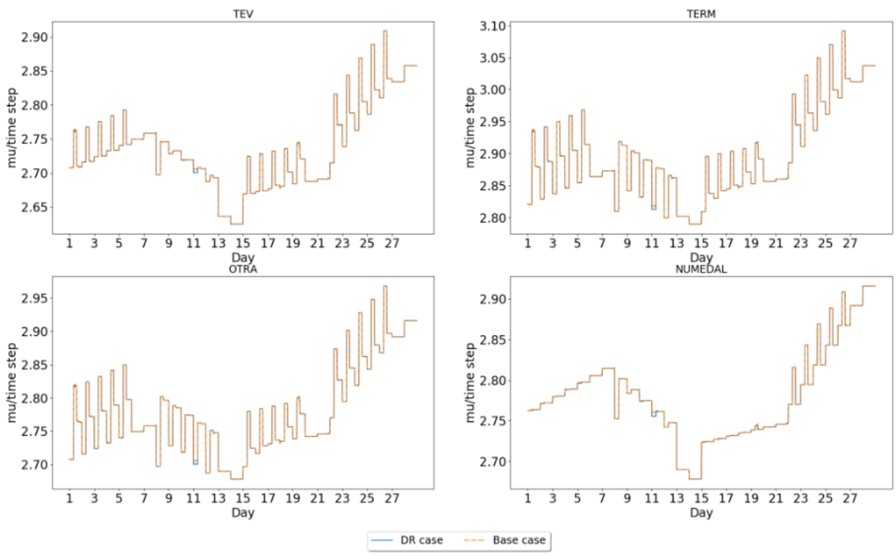

Figure 5.12: Price change for each area in the fall due to DR.

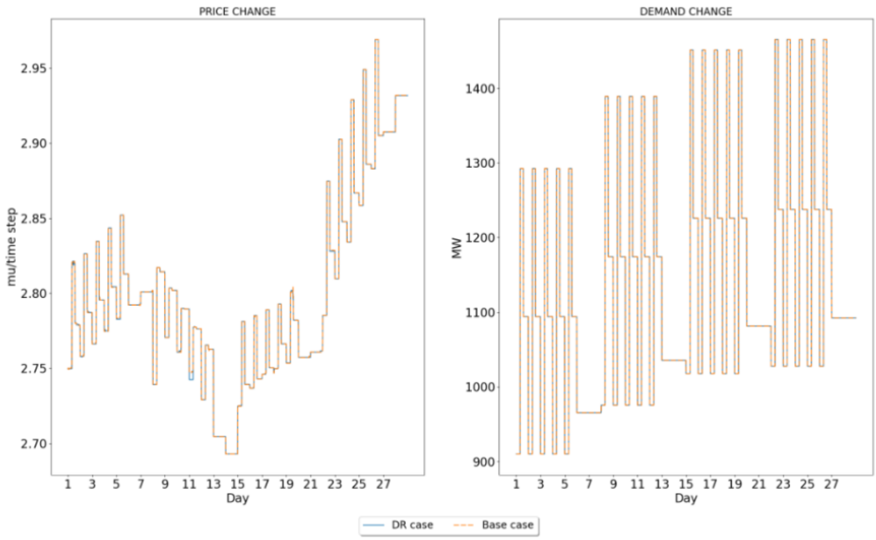

Figure 5.13: System demand and price change in the fall due to DR.

Difference in the seasons
From table 5.8 there is shown that the peak demand is decreasing in the winter and spring due to demand response. In the winter the potential is the most prominent and has decreased the peak demand between 8 to 9 % in the hydropower area and the thermal area by above 3%. In the summer and fall, the change in the peak demand is equal to zero as the price is below the compensation cost and the demand response has not been activated. This implies that the price is too low to favor demand response and the cost of the technology is too expensive. There might be some gradual adaption of consumption, but here the prices are too low to activate reduction on the price-elastic step on the flexible firm demand curve since the first step on the flexible firm demand curve has a price of 25 mu/units and also when the price is low the consumption will go towards maximum capacity.

Season	Numedal	Otra	TEV	TERM
Winter	8.43	8.22	9.02	3.325
Spring	4.94	5.97	6.32	2.92
Summer	0.00	0.00	0.00	0.00
Fall	0.00	0.00	0.00	0.00

Table 5.8: Total peak demand change in percentage per season.

	Demand change [%]				Price change [%]			
Season	Numedal	Otra	TEV	TERM	Numedal	Otra	TEV	TERM
Winter	2.00	1.93	2.16	0.76	1.55	1.77	1.76	1.66
Spring	1.09	0.68	1.48	1.37	0.76	0.79	0.79	0.79
Summer	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fall	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 5.9: Change in demand and price in each area per season.

For the system, the change in the winter for the demand is 1.63% and price 1.68%. While in the spring the changes are 1.14% for demand and 0.78% for the price as shown in table 5.10. For summer and fall, the system change is 0% for the price while the demand is 0% for the fall and the summer 0.01% which is marginal.

Week	Demand change [%]	Price change [%]
Winter	1.63	1.68
Spring	1.14	0.78
Summer	0.01	0.00
Fall	0.00	0.00

Table 5.10: System demand and price changes in the winter due to DR.

The potential of price-based demand response lays in the seasons where the prices are above the compensation cost of demand side management. The case above shows that these seasons are winter and spring. Still, there might be potential in the summer and fall since the price and demand are modeled strictly inelastic and the variation within the day is not captured. The peak and off-peak demand are not modeled accurately as the spot price shown in the day-ahead market varies more. The potential of price-based demand response in the summer and fall might not be scheduled, but rather a reason for the use of reserves whenever the demand and supply are not in balance due to intermittent energy and demand that was not foreseen.

Demand response should be used both in the scheduling planning, having aggregator in the day-ahead market to make use of the demand potential, but also in the capacity market creating reserve mechanisms from demand response.

5.2 Change in reservoir level

In this case, there will be investigated the winter periods where the reservoir level is lower and equal to the median level. This is to capture times with higher prices as it is based on that, historical, the peak hours happen in the winter months. There are chosen reservoir levels of 68.5% (median), 50% and 30% were PriMod is solved from week 1 to 5. There will be looked into areas and system prices and demand.

Results

Area

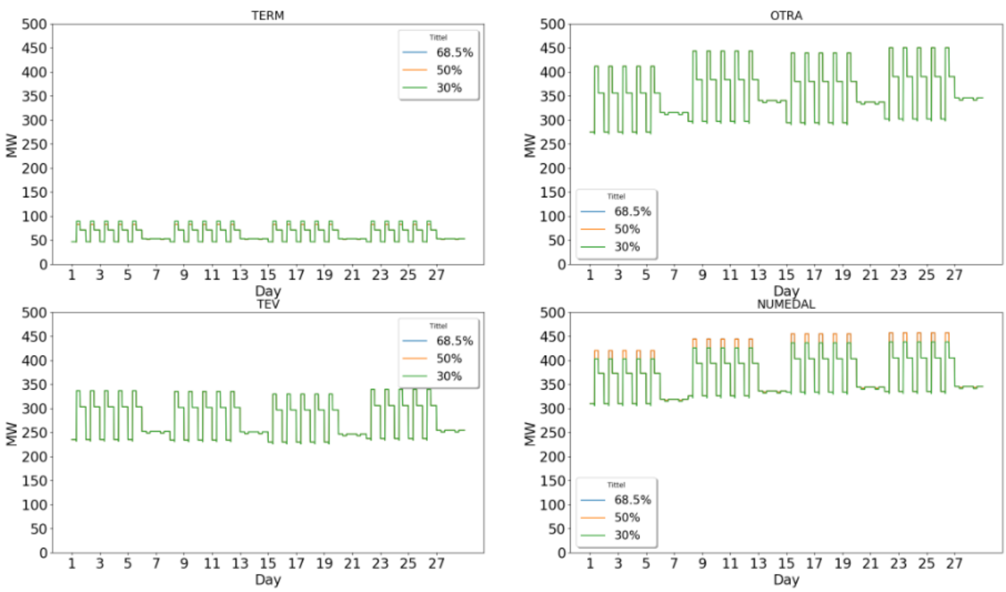

Figure 5.14: Area demand with a changing reservoir level.

Figure 5.14 show that the areas that see a change are TERM and Numedal. In TERM demand increases as the reservoir level is 30% of its maximum. For Numedal the demand has decreased for the same reservoir level. For the two other areas, there is no change in demand and therefore not affected by the change in reservoir level.

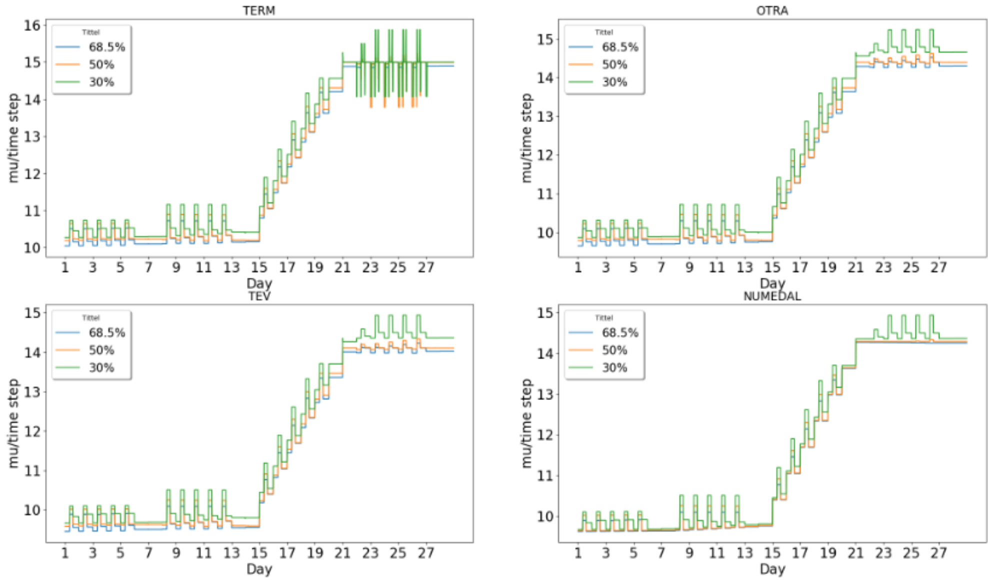

Figure 5.15: Area prices with a changing reservoir level.

	Demand change [%]				Price change [%]			
Reservoir	Numedal	Otra	TEV	TERM	Numedal	Otra	TEV	TERM
50%	0.00	0.00	0.00	0.00	-0.54	-0.70	-0.70	-0.31
30%	1.06	0.00	0.00	-0.83	-1.68	-2.66	-2.65	-1.52

Table 5.11: Change in demand and price compared to reservoir level of 68.5% for the whole periods.

The price, on the other hand, is different from the demand. In figure 5.15 and table 5.11 shows that the price increases as the reservoir level decreases for all areas. This is due to a change in reservoir level that affects the water value which is they are inversely proportional.

System

When the reservoir level decreases this implies that the water value increase which produces a higher price in the system. From figure 5.16 we see that when the reservoir level decreases the price increase in the system. Further, the demand stays close to the same, but when the reservoir level gets closer to zero the demand will decrease since the cost is higher.

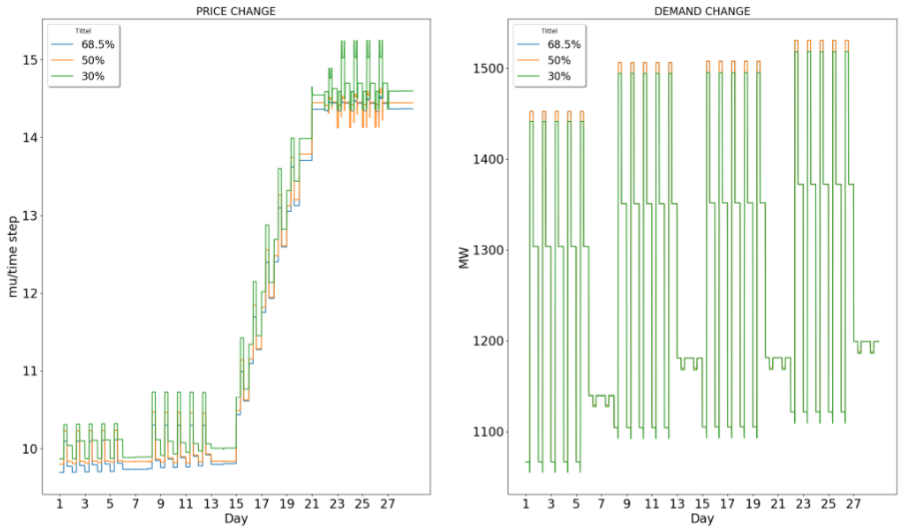

Figure 5.16: System price and demand variations with varying reservoir levels.

Reservoir	Demand change [%]	Price change [%]
50%	0.00	-0.56
30%	0.18	-2.12

Table 5.12: Change in system price and demand compared to reservoir level of 68.5%.

Demand in the reservoir level of 30% has decreased by 0.18 %, but the price has increased with 2.12% compared to the reservoir level of 68.5%. When the reservoir level is 50% the price has increased with 0.56% and demand is equal to the reservoir level of 68.5%. We see here that the reservoir has to be equal or below 30% to reduce demand. This might be due to a high compensation cost of load shifting and the fact that we have a restriction that limits how low the demand can be in these hours. The price variations for the different reservoir levels lay more in that the water value has increased introducing a higher price and the demand response is still there but has not increased its potential.

5.3 Flexible loads

Since the potential of load shifting was not accounted for in the seasonal and reservoir level case there will be presented a case to force the load shifting to account. The compensation cost will be set to zero and the curtailment percentage equal to zero making the load shifting the only DSM used.

PriMod has been solved with three different percentages for the flexible loads where they can be shifted, 5%, 10 %, and 15%. The choice of the percentage is to show what happens when the share of flexible demand, in terms of EVs and smart appliances, increases. The season chosen is the winter since it is the period where the potential for demand response is greatest due to high prices and demand.

Results

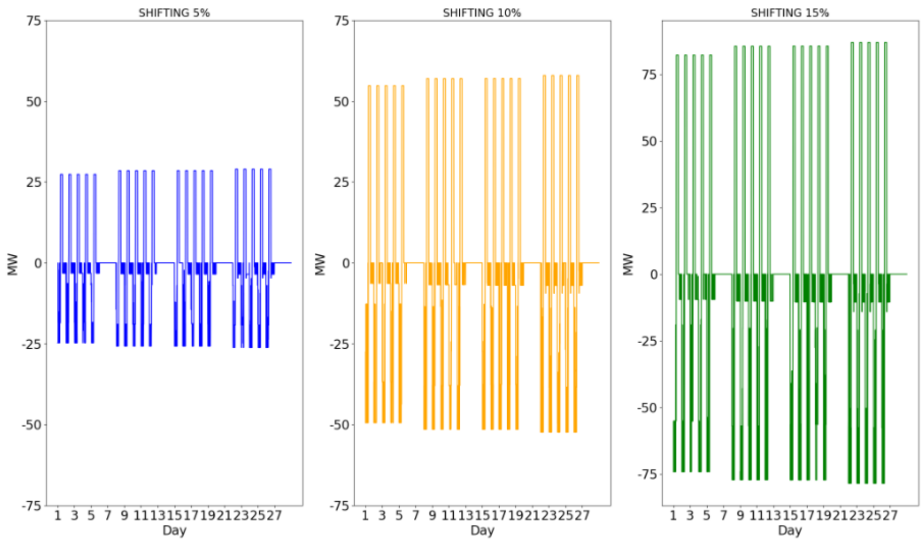

Figure 5.17: Amount shifted demand for different levels of flexible loads.

Figure 5.17 show how much of the demand is shifted in the period. The demand in those hours that demand is shifted from is constantly cut off with the same amount of capacity while the off-peak hours have a more variable demand profile. This is due to that the optimization model wants to minimize the cost. The price for the peak hours is the same while the other hours vary indicating that the optimization model is going to move loads to the hours with the lowest price until the restrictions are met.

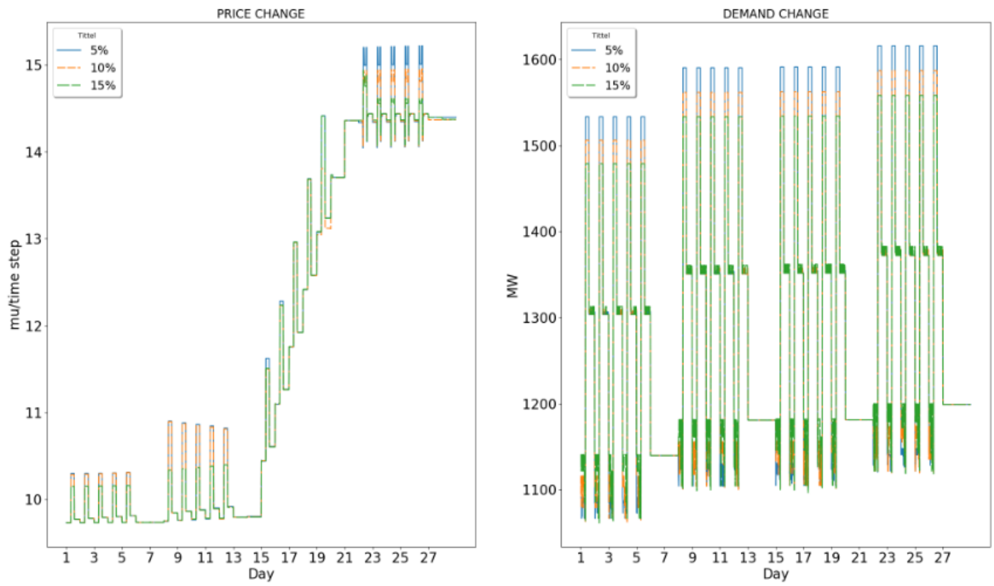

Figure 5.18: System price and demand change

In figure 5.18 the demand and price variations is plotted. It shows that when the flexible load increase the peak demand decreases. We can also see that the load is shifted as in the off-peak hours the graph with a higher flexible load has a higher demand in these hours but in contrast, they decrease the demand in the peak hours. Suggesting that with a high flexible load percentage, the demand profile will even itself out when there is no compensation cost.

Percent	Max shifted[MW]	Peak demand[%]	Price[%]
5%	28.98	1.77	0.90
10%	57.95	2.17	1.08
15%	86.93	5.32	1.31

Table 5.13: Change in system due to load shifting.

Table 5.13 show the maximum capacity that had been shifted in the period, the decrease in peak demand for the system in percentage and the decrease in system price in percentage over the whole period. It shows that the price and peak demand decrease with load shifting. The benefits from demand response increase with the increasing share of flexible loads in terms of shiftable loads.

5.4 Discussion

The seasons have an impact on the potential of price-based demand response. The price seen in the case season variation was the parameter that would affect how much of the demand that was curtailed and shifted. Reason being that the price had to be above the compensation cost to curtail demand and shift loads. To activate load shifting the difference between the peak and the off-peak price had to be greater than the compensation cost. From the season variations, winter and spring were the favorable seasons for demand response. In the winter, it had great potential when it came to a reduction in the peak demand. In the spring, the reduction in price and demand was not as great but still had the potential to decrease the price and demand. Though the calculated potential in the summer and fall was zero there might be potential for demand response for all seasons, but not visible in power scheduling. Reason being that the unforeseen imbalance in the system coming from intermittent generation creates a need for other reserves in the balancing market to cope with the changes. Price-based demand response can not in itself work as resources here since the price is set before the operation time. Instead, demand response in terms of direct control can be a resource to provide reserves in terms of FFR as it can respond faster than hydropower generation. Indicating that price-based demand response only has an impact on the day-ahead market and intraday market if we were to assume that there are aggregators with demand portfolio in these markets.

The reservoir level had an impact on the area and system price. The case indicated that there were changes in the demand due to an increase in the price as the reservoir level decreased. When looking at the demand there was not much of a change suggesting there were other reasons for the increase in the price. The situation that might have caused it is that when the reservoir level decreases the water value increases leading the price in the hydropower areas to increase. Due to transmission, this will impact the thermal area too as it has the highest price of the areas, hence an importer of power. Still, there should have been more demand that was affected by the price-based demand response due to a higher price, but since the demand is modeled mostly inelastic it will not be affected by the price. The share of flexible demand, used for DSM, and the price-elastic market steps are the demand affected by the price, but the area price is below the market step price for the elastic share and the flexible firm demand indicating that the gradual adaption of consumption would not affect the demand to decrease. In the optimization model for DR, there was created restrictions to the maximum and minimum capacity level of the demand profile making it difficult for the demand to decrease further. Hence the reservoir level has an impact on the prices that are set before the price-based demand response is activated meaning that the demand response will be equal or a bit greater than when the reservoir level as at its median level. The price-based demand response is in place and has potential, but the price difference should be greater such that it could have activated the load shifting.

Curtailment was in the two first cases, the technology favored due to a high compensation cost that did not activate load shifting. Load shifting was in the flexible load case activated and seen that there was potential for price-based demand response from this technology. This was though restricted by the compensation cost of the technology that was set to zero and the absence of curtailment. It did not give the right impression at how it would work as assumptions were used to favor load shifting. Still, there was an effect of decreasing the peak demand and the price in the system. Hence the load shifting can decrease the peak demand and the price while making sure the total amount of demand stays the same. Also observed from the case, increasing the flexible demand in the system will decrease the peak demand and price until the capacity reaches its limit. Seen from table 5.13, the relationship between the amount of flexible demand and changes in demand and price is logarithmically.

From all cases, we see that the potential for demand response is dependent upon the price and amount of flexible loads. The price is the parameter when solving the optimization model for DR meaning that the demand is adjusted upon the price set in the market. The pricing that has been used is real-time pricing as the tariff. If we were to account for more demand response in the future, governments can be a contributor to change the tariff to make it favorable to have more demand response in the grid. Critical peak pricing can be a resource that will favor load shifting and curtailment as the price is high enough to make both of the technology cost-effective in the objective function and making sure that there is a high enough difference between off-peak and peak hours such that load shifting can be activated, assumed that there is a compensation cost to it. Time of use tariff can also favor these technologies for demand response. These tariffs can be a resource to schedule the production better when we assume that there are technologies that are implemented in the residential sector as AMS and smart appliances. There is an increased potential of the demand response as the EU is making more energy come from renewable energy resources which will increase the penetration of VER. This will change the generation profile in the thermal areas and making the prices more variable here which will impact the hydropower areas further. Also, the demand response seen, can be used as reserves and further implemented into the reserve restriction that was not activated when solving PriMod. Demand response has the potential to respond fast meaning that it can both work as a resource in a demand-portfolio in the day-ahead market, but also in the balancing market as a reserve in the capacity market and in the new development of FFR.

The discussion above is made under assumptions towards implementing demand response. A challenge mentioned towards demand response is that it is modeled with several assumptions that do not give the real benefit. Assumptions that contributes to this challenge in the results is that the compensation cost had a time limit for shifting and curtailment of two hours in the article. In the modeling, the time was set to six hours to cover the whole period where the peak demand is the same. This would instead have increased the compensation cost as there is more discomfort towards the end-users as there was the same compensation cost chosen. The reason for the choice is that there is a power scheduling model and from the results, it is evident that the load profile does not correspond to the load profile in the day-ahead market. The demand is modeled strictly inelastic which does not give the full potential of price-based demand response, hereunder gradual adaption of consumption.

Another effect of the price-based demand response that lacks potential is that the prices generated are too low compared to the compensation cost which sets the potential of load shifting in the cases to zero. That the prices are too low effect the gradual adaption of consumption also since the few steps that have price-elasticity is more expensive than the area prices. The limitation of demand response was set to the residential sector. The potential in the power-sensitive industry has not been investigated and this was in the Nordic system said to have potential and can provide demand response. Hence the full potential of demand response has not yet been discovered. The reserves restriction in PriMod was deactivated to capture a greater potential of demand response and to decrease the time for solving the model. If the potential increase is can not necessarily said to be true but needs to be further investigated as the reserves are important for balancing services and also to see the full impact of the price-based demand response.

Chapter 6

Conclusion

The potential and impact of price-based demand response in a short-term hydro-thermal model have been investigated. There was presented a method for how to implement demand response restrictions and an additional optimization model towards the short-term scheduling model, PriMod, developed by SINTEF Energy Research.

Findings from the literature and the results show that price-based demand response in a weekly scheduling model of hydropower has the impact to decrease the demand, the peak demand, and the prices due to DSM. This is beneficial for reducing the imbalances in the production side as the peak demand and VER are increasing. The impact demand response has on the different markets within the Nordic power market is variable. Demand response was in the power scheduling needed to optimize the bidding into the day-ahead market and in the balancing market due to the implementation of FFR as hydropower generation was not qualified for this reserve. There was also an increasing need for model hydropower scheduling more thoroughly as to reduce VER curtailment and cost. Seen from the result, demand response could with a more detailed scheduling decrease the prices even further.

In the winter season, the reduction in the demand and price was above 1.60% over four weeks. In the spring, the reduction was 1.14% and 0.78% for demand and price respectively. The summer and winter indicated no potential of price-based demand response due to low prices compared to the compensation cost. The impact of price-based demand response may lead to a decrease in investment cost in the grid and lower the electricity bill. A marginal difference for an end-user, but the social welfare will have a great impact as to lower the network charges.

Decreasing the reservoir level from its median did not impact the demand or the price coming from price-based demand response since the demand was modeled strictly inelastic. The effect of the increase in price was due to an increase in water value. When increasing the flexible loads the effect is a decrease in the demand and price. The relationship seen between the increasing share of flexible loads towards changes is logarithmically asserting that with a higher share of flexible loads the impact from price-based demand response increases, most in the beginning. The areas that had the greatest impact of price-based demand response were the one with the highest amount of flexible loads seen in all cases, here the hydropower areas.

The cases were solved without reserves meaning that balancing needs towards the capacity market had not been accounted for. Additional reserves can come from price-based demand response or from aggregators that have demand portfolios. Another solution might be companies as Tibber to work in the capacity market where they respond to signal sent from TSOs due to imbalances in the system. This indicates that in the future demand response should be modeled into the reserve restrictions.

Though short-term scheduling is modeled more detailed then other scheduling models, it is not detailed enough to capture the whole impact of price-based demand response in the system. On a weekly scheduling process, there can be stated that the impact the demand response has is that it will reduce the prices, the peak demand, and the demand if curtailment is in-placed. The assumption for affirming this is that there are flexible loads, the compensation cost is affordable compared to the system and area price, and that the consumer has a relationship to the price or has used market actors that can adjust their consumption when it comes to DSM. The water value is the parameter affected by the decrease in demand from week to week from the price-based demand response. When the demand decrease, the reservoir level increase which leads to a reduction in the water value which is an essential parameter in a hydropower scheduling model. As FanSi is used, the reservoirs are more detailed formulated with its water values making the demand response affecting the specific regions more closely. The modeling part of the demand is crucial for the effect of price-based demand response as the gradual adaption of consumption was not activated with any difference in this thesis due to that demand was modeled mostly inelastic and prices were to low.

Further work

In the future, there is still an increasing need to discuss and investigate the potential of demand response both on the lower level and on a scheduling level where loads are aggregated to capture the system and areas impact. The findings that lacked reliability would need to be investigated more and these are presented below.

- Investigate the potential from other sectors as a power-sensitive industry and commercial sector.
- Model demand response into the reserve restrictions.
- Model demand response more elastic to activate gradual adaption of consumption and also get a better look at DSM.
- Consumers working as up-regulation on the consumer side. Meaning that when there is excessive production the consumer can increase their consumption.
- Implementation of more IT systems in the residential sector to capture the benefits from demand response.
- Tariff structure should be investigated to open the door for price-based demand response to act better in the system.

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Appendix

Shifting and curtailment

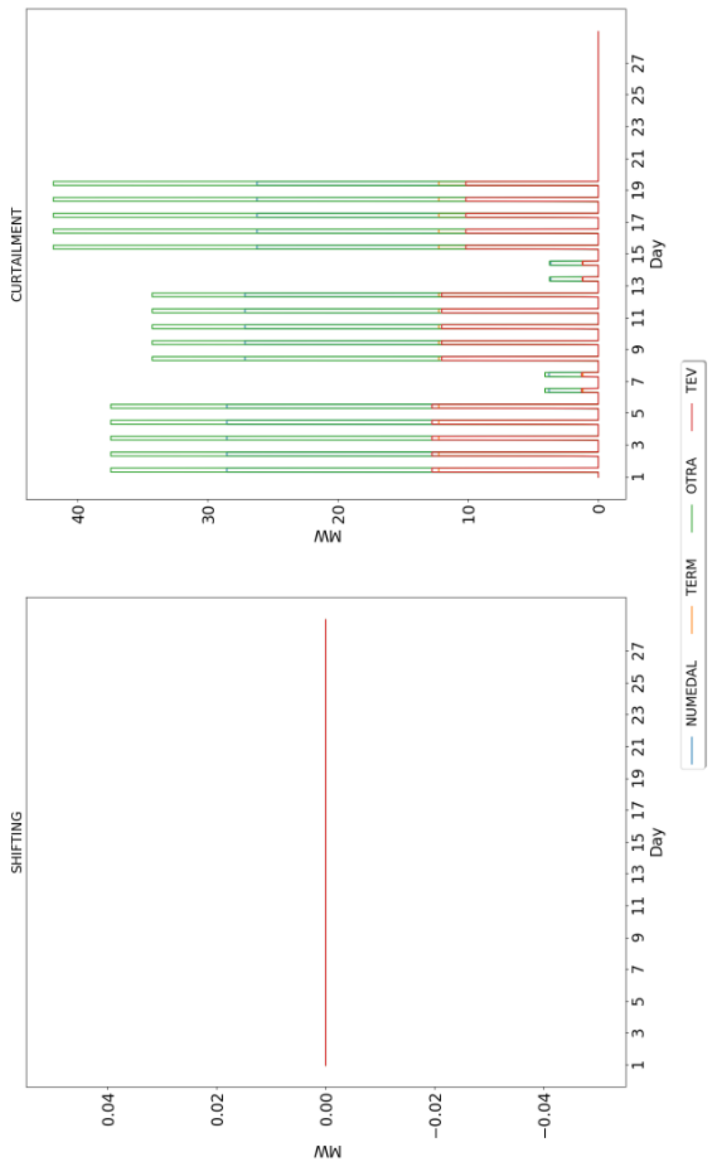

Figure 6.1: Load shifting and curtailment spring.

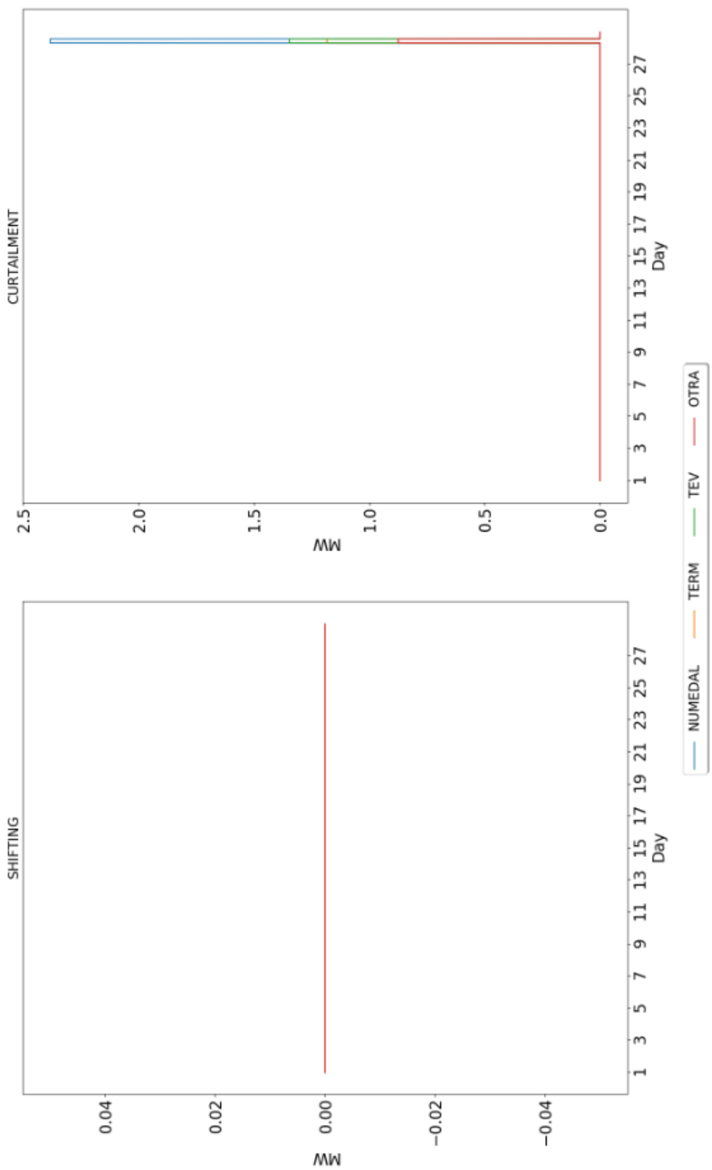

Figure 6.2: Load shifting and curtailment summer.

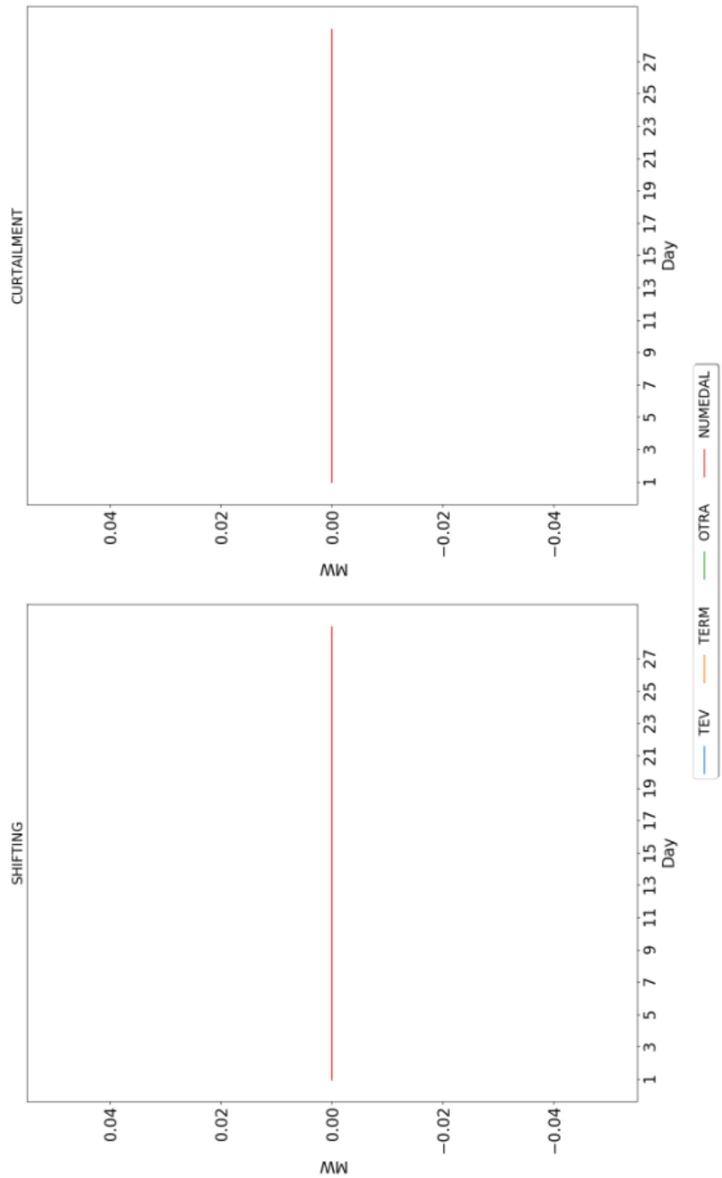

Figure 6.3: Load shifting and curtailment fall.

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