Siri Hartvedt Nordén

Hydro-Thermal Multi-Market Optimization

Economic surplus

Master's thesis in Energy and Environmental Engineering

Supervisor: Arild Helseth

June 2019

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Norwegian University of Science and Technology
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Abstract

Fundamental modeling of the power system is essential to provide decision support for investments and optimal system operation. With increased penetration of intermittent generation and the outfacing of coal and nuclear power, it is expected that more dispatchable capacity will be held out of the energy market to provide balancing services. With more generation reserved in capacity markets, the fundamental market models need to be re-visited as they mostly consider the product of energy. This serves as the motivation for this thesis which further develops a prototype under development for fundamental hydro-thermal multi-market modeling, referred as PriMod.

The main objective of this thesis has been the implementation of constraints regarding up and down regulation and to investigate the impact different allocation methods and reserve volumes has on the power system. Both reservation of capacity within the entire Nordic power system and within each price zone is tested. In addition, a tool to analyze how the economic surplus distributes has been created. The simulations are run over a winter week and a summer week to analyze the impact of different climatic conditions.

The results show that increased volumes for up regulating reserves increase the energy prices. The effect is most prominent at the price peaks during winter when the load is high. Contrarily, increased volumes of down regulating capacity decrease the energy prices, mostly during summer when the load is at its lowest. This underlines that for increased volumes of reserves procured in balancing markets, the price impact in the energy market is significant, highlighting the need for a fundamental multi-market model.

Moreover, the results illustrate that up regulating prices increase during winter as expensive thermal units supply up regulation at expensive costs. In the summer, the down regulating prices increase with increased reservation volumes as hydro power stations are forced to produce energy at lost profit. The lost profit achieved by forcing production for down regulating or holding back capacity for up regulation will be compensated by the TSO. Individually, the reservation costs for up regulation in week 9 are more expensive than the down regulation costs in week 31 for the same amount of reserved capacity. However, combined the total reservation costs are higher in week 31 as both up and down regulation becomes costly.

Regarding the welfare calculations, increased reserve procurement decreases the consumer surplus during winter as the energy prices increase and increases the consumer surplus during summer when the energy prices decrease. The producer surplus follows the opposite trend. However, in the calculations of surplus from hydro power, there are some irregularities as the producer surplus depends on the water values and the future costs of water. Since the different simulations handles reservoirs differently, the costs of hydro power are different in the simulations. Further investigation of the producer surplus from hydro power is therefore needed. Resultingly, the total surplus does not decrease for increased reserve procurement as would be expected.

The thesis results indicate that PriMod shows great potential in serving as a fundamental multi-market model, but still lacks some details in the handling of reserve units to obtain realistic modeling of the balancing markets.

Sammendrag

Fundamental optimering av kraftsystemet er essensielt for å anskaffe korrekt beslutningsstøtte for investeringer og for optimal drift av kraftsystemet. Med en økt andel av ukontrollerbare energikilder og utfasing av kull og atomkraft forventes det at en høyere andel av regulerbar kapasitet holdes ute av energimarkedet for å tilby balansetjenester. Når en høyere andel kapasitet reserveres i balansemarkedene må de fundamentale markedsmodellene bli revurdert ettersom de i hovedsak kun vurderer energi. Derfor vil denne masteroppgaven videreutvikle en prototype under utvikling for fundamental multi-marked hydro-termisk modellering ved navn PriMod.

Målet med denne oppgaven har vært å inkludere krav for opp- og nedregulerende kapasitet i modellen og undersøke hvordan ulike allokeringsmetoder og volumkrav påvirker kraftsystemet. Både reserveallokering innenfor hele norden og innenfor hvert prisområde er testet. I tillegg er et verktøy for å analysere hvordan det økonomiske overskuddet fordeles lagt til. Simuleringene er kjørt over en sommer- og en vinteruke for å teste hvordan modellen responderer ved ulike klimatiske forhold.

Resultatene viser at økte reservevolumer for oppregulering øker områdeprisen for energi. Effekten er mest tydelig om vinteren når lasten er på sitt høyeste. På omvendt vis fører økte volumer nedregulering til synkende områdepriser, spesielt om sommeren når etterspørselen etter energi er lav. Dette understreker at økte volumer i reservemarkedene vil ha en signifikant påvirkning på energiprisene. Dette viser at behovet for en fundamental multi-markedsmodell er essensielt for korrekt modellering av kraftsystemet.

Videre illustrerer resultatene at oppreguleringsprisen øker om vinteren når termiske kraftverk tilbyr reserver til høy pris. Om sommeren øker nedreguleringsprisen da kraftsystemet må tvinge inn produksjon fra dyre vannkraftverk som kjører med tap. For å kompensere for de tapte inntektene må systemoperatøren betale tilbyderne av reserver for sin kapasitet. Simuleringene viser at denne systemkostnaden er høyest om sommeren når både opp- og ned regulering blir kostbart. Alene er oppregulering dyrere i uke 9 enn nedregulering er i uke 31 for samme mengde reserver.

Ved å betrakte de økonomiske beregningene kan det observeres at økte reserver senker konsumentoverskuddet om vinteren og øker det om sommeren ettersom systemprisen endres. Produsentoverskuddet følger motsatt trend. Selv om produsent- og konsumentoverskuddet endrer seg som forventet, synker ikke det totale overskuddet med strengere reservekrav. Ettersom de ulike scenarioene håndterer reservoarene ulikt, blir kostnadene for vannkraft ulike. Videre analyser må derfor til for å undersøke hvordan vannverdiene korrekt kan representeres. Dette resulterer i økt økonomisk overskudd i tilfeller der det motsatte er forventet.

Alt i alt viser PriMod lovende resultater til å bli en velfungerende fundamental multi-markeds modell, men mangler fortsatt en del detaljer rundt håndteringen av genererende enhetene som tilbyr reserver for å kunne modellere balansemarkedene korrekt.

Preface

This thesis was written at the department of Electrical Power Engineering at the Norwegian University of Science and technology during the spring semester of 2019. The thesis was carried out in collaboration with SINTEF Energy Research as a part of the PriBas project.

I would like to express my gratitude towards my supervisor Arild Helseth, for always being available for guidance and many interesting discussions. I would also like to thank PhD. Christian Oyn Navesen for the help with programming and understanding the model. Without any experience with Python before the specialization project, your help has been truly invaluable. Lastly, Mari Haugen at SINTEF deserves a big thanks for helping me understand the applied dataset and for many discussions about the consecutively results achieved during the semester.

Finally, I must thank my fellow students for the encouragement during the semester and always making me look forward to a new day at the university.

Trondheim, 15.06.2019
Siri Hartvedt Nordén

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Chapter 1: Introduction

1.1 Thesis motivation

In 2018 the European council agreed to increase the renewable share of power production to 32 % by 2030(1). This is an increase with 5 % from the previous goal of 27 % from 2014. To achieve this, all member states are required to draft a 10-year National energy and climate plan by the end of 2019 outlining how each nation will reach the new goal. Germany has set the most ambitious target of 65 % renewable energy consumption by 2030, representing a doubling from today's level of 35 % (2).

To achieve such ambitious targets different measures in all levels of the power system must be implemented. This includes changes in both supply and demand side of the power system in addition to grid development. On the supply side, it is expected that both the installed wind and PV capacity will increase drastically over the next ten years. Moreover, the outfacing of lignite and nuclear power will reduce the amount of power from fossil and radioactive sources. However, replacing large shares of dispatchable generation with intermittent, uncontrollable sources as wind and PV challenges the system stability as the power system needs instances to quickly respond to changes in load and generation. As generation and consumption always must be balanced and as the power output from most renewable sources only depend on uncertain external factors, the need for flexibility in the power system increases.

To balance the future power system, it is expected that significant amounts of capacity reserves will be held out of the energy market to compensate for the lost controllability. In addition, it is expected that the flexibility can be provided through a more interconnected Europe, optimizing the utilization of resources. In that case, the areas with a surplus from renewable energy can export energy to areas with power deficit and vice versa in addition to exchanging balancing services.

As Norway is dominated by flexible and renewable hydro power, it provides an unique opportunity to supply its neighboring areas with the much needed flexibility. Today Norway have an exchange capacity of 6095 MW abroad and with the new cables NorLink and North Sea Link to Germany and and Great Britain the export capacity will increase to 8895 MW by 2021(3). With this possibility, Norway could become Europe's supplier of flexibility by holding back some capacity for the balancing markets.

To utilize the flexibility in the power system, the market structure needs to be re-visited. Particularly, the need for well functioning reserve markets are essential to access the flexibility in the interconnected grid. ENTSO-e is currently working on creating an European market platform for exchanging balancing services. In addition, structural changes in the reserve markets are being implemented within the Nordic power system, changing the way we model reserve procurement. To include the trading of reserve products across price areas, the fundamental models in hydro power scheduling must be revisited as most models only concern the product of energy. This serves av the basis of this thesis, which utilizes and further develops a new prototype for fundamental hydro-thermal multi-market modeling provided by SINTEF Energy Research.

1.2 Problem formulation

As the future European power system will be more interconnected and include a larger share of intermittent generation, it will require that significant amounts of capacity reserves are held out of the energy market to balance the non-dispatchable generation. Fundamental market models are much in use in the Nordic market to e. g make price forecasts for electricity. In such models, reserve capacity can be included to forecast reserve prices.

In this thesis, a prototype of a market model under development by the PRIBAS project at SINTEF Energy Research is utilized and further developed. The task includes adding restrictions regarding different types of reserves and to adapt the model such that welfare analyses and economic considerations can be performed. Particularly, how the producer- and consumer surplus is affected by adding requirements on reserve capacity will be analyzed. Furthermore, the thesis will test the model sensitivity with different volumes of reserve procurement.

1.3 Scope and limitations

The research presented in this thesis will focus on the Nordic power system as seen in 2030, including a renewable share reflecting the most ambitious climate targets. To perform the modeling of 2030, this thesis uses a recent version of the under-development PriMod model for multi-market hydro-thermal price forecasting. The prototype is developed as a part of the PRIBAS project at SINTEF Energy Research.

The model concept (which PriMod is a part of) basically comprises two steps. First, it utilizes FanSi(4), an existing long term fundamental model to provide valuation of water. Then a short term operational model under development re-optimizes the power system with a higher level of details. The utilized version of the operational model applies linear and mixed integer programming to solve the objective on daily increments with a three hour time resolution. The short term model is developed using open source Python and the optimization package Pyomo. All of the contributions in this thesis consists of further developing the short term model. The model is implemented with data from HydroCen low emission scenario for 2030 provided by SINTEF. In the dataset, the Nordic hydro dominated system is described with a high degree of detail whereas continental Europe and Great Britain is included in a more aggregated and simplified manner.

This thesis implements restrictions regarding reserve procurement for up and down regulation. The response of the model is tested with sensitivity regarding the amount of reserves procured and how the reserves are distributed. The model is first tested with aggregated reserve procurement, where reserve capacity is procured within the entire Nordic system. Then zonal reserve procurement is implemented, meaning that the reserves are procured within each price zone while allowing cross zonal exchange of reserves.

Moreover, the thesis focuses on implementing a framework for economic considerations in multi market modeling. Primarily, the economic results will highlight how the producer and consumer surplus distributes under different conditions. Therefore, the analysis focuses on testing the model on a short time horizon, in weeks with different traits.

Lastly, the thesis focuses on the coupling of the energy market and the balancing capacity markets. It does therefore not consider activation of reserves.

1.4 Contributions

Within the given framework, the main contributions implemented in this thesis consists of:

- Implementing different types of reservation requirements, e. g up and down regulation
- Implementing the possibility to exchange reserves between price areas
- Facilitating a file to achieve the necessary market data from the model
- Creating a tool to plot and analyze the market clearing for a given time instance in multi-markets
- Performing economic calculations to demonstrate how the different surpluses distributes
- Investigate and evaluate how the model performs under different requirements of reserve procurement

1.5 Outline

The body of the thesis is structured in the following way:

Chapter 1 describes the motivation for the master thesis and includes the problem formulation, scope and highlights the contributions implemented by the author.

Chapter 2 presents relevant theory regarding power markets, surplus calculations in power systems and hydro power scheduling. Moreover, it describes relevant literature and places the applied prototype in context.

Chapter 3 consists of a detailed description of the model methodology and couples the theory of hydro power scheduling with how PriMod operates. Furthermore, the objective and constraints of the operational model is presented in addition to the implemented method for economic considerations.

Chapter 4 covers the dataset applied and describes the given input regarding supply, demand, exchange and the system topology.

Chapter 5 aims to describe the case study performed in chapter 6. The description includes a presentation of the data and methodology implemented by the author.

Chapter 6 presents all relevant results from the case study. Particularly results regarding how the area and reservation prices changes for increased reserve procurement is presented. In addition, results regarding the distribution of consumer surplus, producer surplus and reservation costs are presented for each case.

Chapter 7 discusses the results presented in chapter 6, comments the validity and limitation of the model and couples the theory and results.

Chapter 8 sums up the key findings and concludes the thesis before suggested future work is presented.

Chapter 2: Theory

This chapter will present relevant theory regarding power markets and optimization. First a literature review will expose similar research and indicate the relevance of this thesis. Since PriMod enables multi-market modeling, theory on the different power markets will be presented, followed by the economic theory on welfare calculations in power markets. Lastly, some optimization theory on hydro power scheduling will highlight how to model the different power markets in a hydro dominated system.

2.1 Relevant literature

As this master thesis takes use of and further develops a prototype under development for fundamental multi-market modeling, relevant research regarding this model will be presented. Then the model will be placed in context with other fundamental models. Furthermore, the litterateur survey will expose similar research studies regarding socioeconomic surplus in power systems and reserve procurement.

The paper *Multi-Market Price Forecasting in Hydro-Thermal Power Systems* by Helseth et al. (5) was the first published article about PriMod. Helseth et al. describes the basic framework of the model and highlights how the model is split in a strategic part providing valuation of water and a short term operational part, re-optimizing the power system with a higher degree of details. In the study, reserve procurement of 4000 MW is included and the author shows how the price increases as a result of the withdrawn capacity. Further, Ada Strand utilizes PriMod in her master thesis *Optimizing weekly hydropower scheduling in a future power system* (6). Strand further develops the model by adding ramping on HVDC cables, start/stop costs on thermal units and receding horizon methodology. She then runs and tests the model on a simplified dataset with four price areas. Moreover, Strand addresses the shortcomings of the model and necessary improvements to achieve realistic results. Particularly she mentions that the calculation of socio-economic surplus for use as a key performance index in comparisons of cases should be implemented. As PriMod is a model under development, many of Strands concerns are being addressed and improved by SINTEF. However, the calculation of a socio-economic surplus index will be developed in this thesis.

PriMod combines an existing long term fundamental model with a short-term deterministic model as described by (5; 6). The methodology of PriMods short term model is described in detail in chapter 3. The suggested long term models in PriMod are the EMPS model and the FanSi model. In *Hydro reservoir handling in Norway before and after deregulation* (7), the methodology of the EMPS model is described in detail. This model is considered as the industry standard and is widely used for long term modeling. The EMPS model is stochastic, aggregates reservoirs and uses a heuristic approach to find the water values. This simplification is done to reduce the calculation time of the complex problem. The methodology of the FanSi model is presented in *Sovn model implementation* (8). FanSi is also a stochastic model, finding individual water values trough generating a set of benders cuts. The mathematical formulation of finding the benders cuts is well described in (9). Both Jorgen Arstan and Sigrun Morland compare and discuss the use of FanSi versus the EMPS model in their master thesis'. They both conclude that FanSi has proven to give more accurate results and higher socioeconomis surplus than EMPS, however at the cost of much higher calculation times (10; 11).

Common fundamental models utilized in hydro-thermal optimization in the Nordic market are as mentioned the EMPS and the FanSi model. In addition, ProdRisk is a model used in long- and medium term hydropower optimization based on stochastic dual dynamic programming(SDDP). ProdRisk can both serve as a fundamental and a non-fundamental model as it can solve the same problem as FanSi and EMPS regarding the market description and the detailed hydro description. However, ProdRisk is more commonly used for scheduling within a geographical area assuming no internal transmission grid bottlenecks, making it an non-fundamental model as it only considers parts of the power system. It has a stochastic time resolution of one week that can be divided into load blocks with hourly time resolution. Lastly, the model can generate coupled water values/cuts serving as input to a short-term operational planning and thereby providing a consistent coupling between the two (12). SINTEFs model for short-term planning is SHOP. This is the most common model used for short term modeling in the Nordic power system. The model aims to find the optimal use of the water resources within a time resolution of two weeks (13). The main use of the model is to provide bid support in the energy market, distribute the resources in the most optimal way and to estimate the marginal costs as a basis for bidding of options i the reserve capacity market. To provide accurate bidding support, SHOP has a very high level of details. To achieve this within reasonable computation time and to provide accurate bid support for optimal use of the producers portfolio, the model only considers parts of the power system and not the system as a whole.

PriMod is a fundamental model, standing out from the other fundamental models by including a higher degree of details enabling it to provide short term optimization. Being written in open source Python, it is makes easy to add and remove details from the system, creating a flexible framework for fundamental modeling (5). What separates PriMod form other short term models that it is fundamental, considering the entire power system. In comparison to SHOP, PriMod provides a less details, but whereas SHOP aims to provide decision support for bidding in power markets, PriMod aims to provide decision support for investments and system operation. SHOP allows for decision support for bidding in the reserve markets and can therefore be regarded as a multi-market model. However, as it does not consider the power system as a whole, it can not be used on fundamental analysis' studying the overall effect reserve procurement has on the power system.

Type	Long term	Medium term	Short term
Fundamental	EMPS, FanSi	(ProdRisk)	PriMod
Non-fundamental		ProdRisk	SHOP

Table 2.1: Overview over SINTEFs models for hydro-thermal scheduling

For calculation of economic surplus in power systems, both the EMPS and FanSi model uses the methodology described in *Samfunnsøkonomisk overskudd og Samoverskudd* by Ove Wolfgang (14). Wolfgang describes the challenges in surplus calculations in a hydro dominated power system, the relevant market actors and how to calculate the different surpluses. One drawback of the presented methodology is that it only considers the product of energy and does not include the economic considerations of ancillary services. Ivar Wangensteen does to some degree talk about the economic considerations of reserve procurement in a technical report about market based solutions on reserve pricing (15). The report discusses the market based pricing of reserves and highlights the general connection between the energy market and the reserve market.

In 2015, Statnett and SvK conducted the Hasle pilot regarding the exchange of cross zonal capacity reservation[CZC] of aFRR between Norway and Sweden. In *Annex NO2 Socio-economic analysis* (16) the economic effect of this study is presented. The methodology of the study suggests that the expected costs of reduced capacity in the day ahead market in the coming week is based on the observed price difference between areas in the present week. The study highlights that if no price impact of CZC is assumed, the cost of reservation equals the reduced congestion rent. To calculate this price difference they used two methods. First, they used Nord Pool Spot calculations, using actual bidding curves, to study the price effect of CZC reservation. The calculations were done for each hour in a period of ten weeks. Then they utilized back-testing of reservation using historical data. The study found that from running Nord Pool Spots optimization with and without the cross zonal reservation the impact on prices were low except on a few hours when the price was high. Consequently, this method is less suitable when prices are high. In the back-testing method, all possible price impact on reservation of CZC were neglected. The method found that for over 70 % of the hours in the data period, 100 MW reservation of CZC could be traded at no cost in both directions. It also concludes that the use of current weeks price difference in general is a good forecast of the price difference the next week. Lastly, the authors emphasize that one should be careful when interpreting the results to narrowly. As the day-ahead market can vary severely from year to year and since the data period in the analysis is short, the results may differ.

Further Gerard Doorman discusses different methods of exchanging balancing resources between the Nordic synchronous system and Netherlands/Germany/Poland in (17). The author presents the different market structures highlights challenges by exchanging primary, secondary and tertiary reserves in different markets. Moreover, the article presents different ways of coupling the markets to allow for the exchange of balancing services. The article does not comment the benefit of such exchange and has not performed any simulations to back its presented solutions.

There exist many articles and research studies regarding the Norwegian hydropower ability to balance the increased share of RES in continental Europe. Magnus Korpås and Ingrid Graabak presents a review of twelve such simulation studies in their article *Balancing of variable wind and solar production in Continental Europe with Nordic hydropower – A review of simulation studies*(18). The review compares how different studies addresses the following subjects; the need for balancing and storage in the future power system, the further development of the Nordic power system, consequences of market solutions and the changes of operational patterns in hydro power systems. The authors concluded that only three of the articles consisted of a high enough share of wind and solar power to reflect the climate goals. In addition, the simulations were in most cases performed by tools with too low time resolution to reflect realistic behavior of wind and PV. The article therefore emphasize that a model with high enough time resolution must be developed to realistically model the variability from the combined production.

To conclude the literature study, few articles have been published about the economic impact on balancing services. The research indicate that there is need for a fundamental model with a high enough time resolution capture the variability from a high share of renewable energy sources and the impact of balancing services. PriMod can serve as this model, but lacks a framework for surplus calculation. Resultingly, this thesis will include different types of balancing services and implement welfare calculations to investigate the economic effect in multi-markets.

2.2 Power markets

The main objective of power markets is to serve as a platform for trading electricity products. Electricity products is commonly separated in the product of energy and ancillary services. Energy is what consumers buy and represents the effect consumed over time, measured in Watt-hours or Joule. Ancillary services is the electricity products needed to maintain the security of supply in the power system. Such services consist of e. g. voltage and frequency control. The frequency represents the monumental power balance and indicates if the system is balanced. If the system is out of balance, electrical equipment can break and economic losses and/or personal damages may occur. To maintain a stable frequency, capacity is reserved in balancing markets. This withdrawn capacity is commonly referred to as reserves or reserve procurement. Balancing the power system is a challenging task due to uncertainties on both consumer and producer side. To account for these uncertainties and to give financial incentives to insure the instantaneous power balance, the Nordic energy market is divided in the following segments:

NASDAQ - The financial market:
The financial market ensures the optimal existence of generation capacity in the power system. The participants are allowed to trade power derivatives to secure prices and to handle risk. This market allows for trade with a longer time horizon than the physical markets and takes use of fundamental long term models to provide decision support regarding investments.

Elspot - Day ahead market:
Elspot is a physical market for energy in the Nordic synchronous region consisting of Norway, Sweden, Finland and East Denmark. The Nordic power system has a deregulated market, meaning that the energy price is set by the market equilibrium. Before noon each day, all market participants who wish to buy or sell energy need to submit their biddings for the next day. The biddings are submitted to Nord Pool whom clear the market and sets the power price for the next 24 hours. The power price is determined by the market equilibrium for each hour as described by figure 2.1. For each producer to decide their bidding support, short term optimization tools are needed. The models must reflect all details regarding the physical system and updated weather forecast to provide bidding support in the day ahead market. Providing accurate biddings is a crucial task as the wrong bids may lead to economic punishments to the power producer.

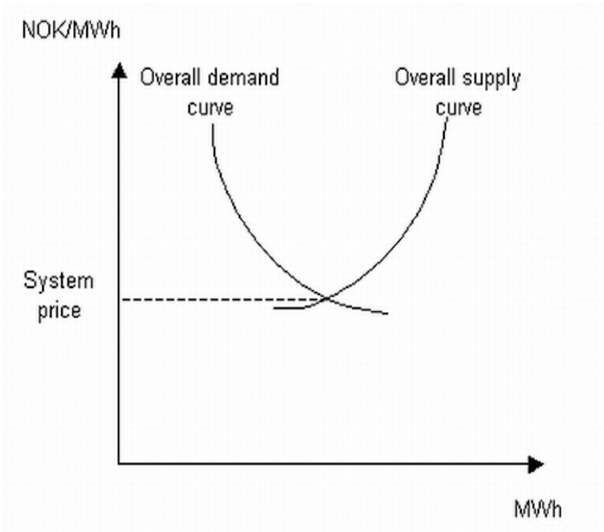


Figure 2.1: Market clearing the day ahead market

Xbid - Intraday market:

Since production and demand always must be equal, the Xbid market exists so that the market participants can insure they deliver their promised service. For example, if a power producer not is able to deliver its bidded energy in Elspot, it can buy itself in balance trough Xbid. This can be done until one hour before the operational hour. If the market bidding deviates from the physical trading, the market actor will be financial responsible for the cost of balancing services. Trading in the intraday market also requires short term scheduling models to aid the decision support for correct bidding. These models has to be run with an even finer time resolution. As the bidding in the intraday market can be done up to one hour before the operational hour, the uncertainties in the system are low. Therefore deterministic models can be used with a high level of assurance of achieving accurate results.

Reserve markets:

If the frequency deviated from 50 Hertz, demand and production are unequal. To stabilize the power system, balancing markets exists to equalize this unbalance. Therefore, the reserve/balancing markets must insure enough up- and down regulation in the system. If the frequency passes 50 Hz, generation exceeds demand. In that case, the system must be down regulated by decreasing the production or increasing demand. Similarly, if the frequency decreases under 50 Hz, load is larger than production and up regulation is needed to increase production or decrease demand. In Norway, the balancing service is operated by the TSO, Statnett, and has to be performed within 15 minutes. To achieve this, the balancing services is split in the instances in table 2.2.

Reserve product	Reaction time
FCR - primary reserves	$30s$
aFRR - secondary reserves	$120 - 210s$
mFRR - tertiary reserves	$\leq 15min$

Table 2.2: Balancing services

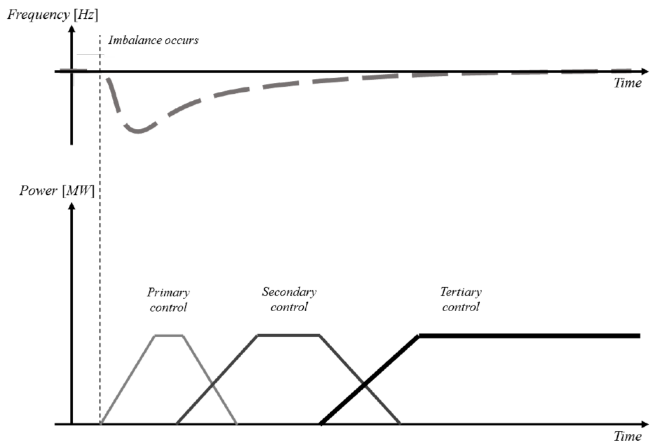


Figure 2.2: Principle activation sequence of reserves after an imbalance (19)

FCR - Primary reserves
FCR, frequency containment reserve, is the first instance responding automatically when an unbalance occurs. The goal of the primary reserves is to stabilize the frequency within 30 seconds to avoid damage to the power system as illustrated by figure 2.2. This is done by controlling the inertia in the system and is offered trough the statics in heavy turbines. FCR is separated in two products, FCR-N and FCR-D. FCR-N is activated in the frequency deviates less than 0.1 Hz and represents normal deviations. FCR-D is used to prevent the frequency of reaching its lower limit and is activated if the frequency falls under 49.9 Hz. These products are offered trough a weekly and a daily market. The market actors can decide if they want to participate in one or in both markets. Bids in the weekly market must be submitted before noon each Thursday for weekdays and before noon each Friday for weekends. In the daily market, the bids must be submitted before 18.00 the day before. In Norway, the TSO requires that all generating units with an effect over 10 MW must have maximum 12 percent statics on units that are not participating in the market (20).

aFRR - Secondary reserves
Automatic frequency restoration reserves, aFRR, is the second instance responding to account for an unbalance in the power system. If a fault remains over several minutes, the secondary reserve will relieve the primary reserve by restoring the frequency to 50 hertz. Figure 2.2 shows that when the aFRR is activated, the frequency restores toward 50 Hz. The TSO automatically activates the secondary reserve by sending a regulating signal to the suppliers' control system changing their production/consumption. The response time of aFRR is 120 -210 s after achieving a signal and the reserve is activated evenly among the all the suppliers in the Nordic power system(21). Market participants delivering aFRR must submit their bids before 13.00 on Thursday the week before. Then the Nordic TSOs decide the amount of secondary reserves to be bought and when to use them. However, a new market solution is under development for both reservation and activation of secondary reserves. This will be described later in this chapter.

mFRR - Tertiary reserves
The last instance in the balancing services are the tertiary reserves, manual frequency restoration reserves, mFRR. The Nordic requirement today, is that any unbalance should be evened out

within 15 minutes. Therefore, the tertiary reserves will relieve the secondary reserve such that the secondary reserve is ready to relieve the primary reserve when needed. Today, the tertiary reserves are required to be turned on for at least one hour and the minimum bid size is required to be 10 MW. This service is provided trough the reserve markets, RKOM and RKM.

RKM is the market for energy reserves in the Nordics where both production and demand can participate. First, the suppliers participating offer the price they are willing to regulate their generation/consumption for. Then the offers are collected in a common list in the Nordics. In theory, the cheapest bids are activated. However, if there are local bottleneck the cheapest bid on the right side of the bottleneck will be activated. The volume supplied by each country in the Nordic power system, is required to equal dimensional fault. In Norway, the dimensional fault is set to 1200 MW. Furthermore, Statnett is considering adding additional 500 MW to deal with local bottlenecks in the system. Bids in this market for the following day are reported to the TSO before 21.30. New bids or correction of bids must be delivered to Statnett at least 45 minutes before the operational hour (22).

To ensure that enough up regulating capacity are available in RKM, capacity is procured through RKOM. In this market, producers are paid to hold back production to insure that sufficient capacity is available in RKM. Both consumption and demand are allowed to participate in this market, but as the required bid size is 10 MW, only power heavy industrial loads are able participate on consumption side. The need for procuring effect in RKOM is mainly during the winter season from October to April. The volumes in RKOM are therefore ensured through seasonal and weekly procurement. In seasonal RKOM, options are bought for the entire winter season. This volumes vary from year to year. In 2018, 647 MW was reserved for the entire winter season. The bids in the seasonal RKOM is cleared 1. October each year. RKOM-week exists to ensure enough capacity each week. Purchases in RKOM-week are carried out by considering the actual power situation based on forecasts in generation, consumption, exchange and probable bottlenecks restricting the system. The volumes in RKOM-week is reserved twofold, one volume is reserved for weekdays and an other volume for the weekend. In RKOM the bids must be submitted before noon each Thursday and Friday for weekdays and weekends respectively (23).

Market	Electricity product	Bid deadline
Elspot	Energy	12.00 day before
Elbas	Energy	One hour before operation
Primary reserves - week	FCR-N	Friday 12.00 week before
Primary reserves - day	FCR-N, FCR-D	18.00 day before
Secondary reserves	aFRR	Thursday 13.00 week before
RKM	mFRR	45 minutes before
RKOM-season	mFRR capacity	1. October
RKOM-week	mFRR capacity	Friday 12.00 week before

Table 2.3: Overview of physical power markets and bid deadlines

Future developments

The future energy landscape will be different from what we see today. As increased shares of renewable energy will penetrate the system, the uncertainties in production will cause an increased need for flexibility in the power system. Moreover, new interconnection and a stronger grid will increase the possibility for cross border trade and harmonization. To insure system balance, new market solutions are under development and it is expected that more dispatchable generation will be reserved in the balancing markets. Moreover, EU has suggested that all the frequency regulating services should be exchanged through international markets. In 2016 the Nordic TSOs signed an agreement to develop a new market for aFRR and work is in progress to create a European market for both aFRR and mFRR. To plan for the future in the hydro dominated Nordics, the models for multi-market price forecasting needs to be re-visited to account for the changes in the market solutions.

The new Nordic balancing concept
Based on the future challenges in the energy landscape, there is a need to improve existing market solutions for reserve products as the current solutions not are providing sufficiently clear and precise price signals. In addition, the financial incentives to ensure that sufficient balancing capacity always is available to the TSO needs to be improved (24). The New balancing concept aims to rethink the fundamental design of how the system is operated and balanced.

The main design features of the new Nordic balancing concept is that each price area should provide sufficient FRR volumes to cover its dimensional fault. Sharing of reserves between areas is allowed while respecting the responsibility of each control area for operational security. Moreover, the exchange of balancing capacity should be secured by reserving capacity on the transmission line. In addition, the new concept requires mFRR to be used for proactive balancing of the system and for congestion management purposes. Automatic FRR should be used for reactive balancing, activated within each bidding zone and coordinated by a central activation optimization function ensuring a optimal border cross bidding zones. Lastly, the balancing parties in the Nordic price zones shall establish a joint balancing market for procurement and activation of reserves. The new market design shall provide adequate price signals for balancing services per 15 minute time period and per bidding zone. (24)

For aFRR, a new Nordic capacity market will take effect from Autumn 2019. The new market will ensure efficient acquiring of aFRR for the TSOs and a common market place for the suppliers. The market development is based on the Hasle pilot described in section 2.1. Moreover, the new market solution aims to double the volumes of available aFRR from 300 MW to 600 MW for all hours of the day within 2021 (25). This new market is a part of the plans for the Nordic Balancing model which includes an activation market that covers the required amount of aFRR within each price area. In other words, first the required aFRR for each price are is found before choosing the cheapest bids in a common optimization. This will also allow for suppliers of aFRR outside of the aFRR capacity market to participate in the delivering of balancing services.

2.3 Economic surplus in power markets

General definition

The calculation of economic surplus is a concept describing the overall effect a product has on the society. The concept is often used to describe the consequences and compare different measures and is a crucial tool for politicians and policy makers.

The economic surplus, also known as the total welfare, normally consists of consumer- and producer surplus(14). Figure 2.3 illustrates the general principle of how the economic surplus is determined. The red curve describes the demand as the consumers marginal willingness to pay and the blue curve represents the supply as the marginal production costs. In a perfect market, the price is given in the equilibrium where marginal costs equals marginal revenue. Moreover, the producer surplus is defined as the sales income minus the production cost represented by the area between the supply curve and the market price in figure 2.3. Similarly, the consumer surplus is represented by the area between the market price an the demand curve equalling the willingness to pay minus the cost of buying the desired quantum. The sum of producer and consumer surplus equals the total welfare(14).

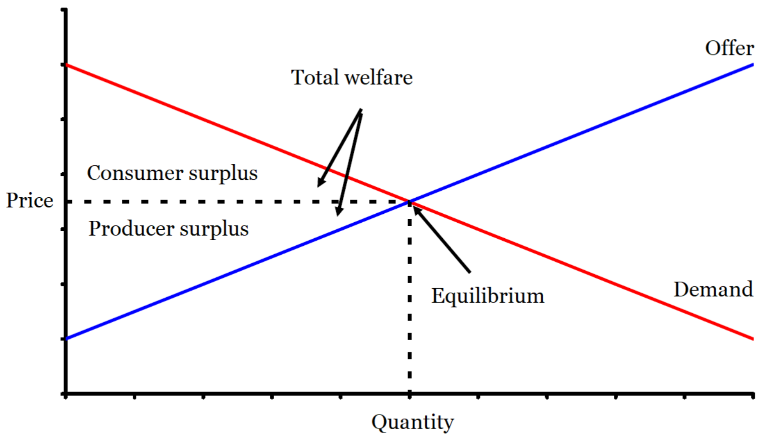


Figure 2.3: Conceptual sketch of economic surplus (14)

Complexity in power markets

The main rule of calculating the economic surplus is that all the economic consequences for all market participants must be included. Analyzing the total welfare of a power system can be a complicated task due to its complex nature.

First of all, electricity itself cannot be stored on any scale, only converted to other forms of energy which can be stored and later reconverted to electricity on demand. As large scale storage technology not yet is economically beneficial, all power generation must be consumed. Resultingly, energy markets offer different electricity products to insure stable power balance. Therefore the total welfare will consist of surpluses from several markets with different characteristics as described by 2.2.

Secondly, the problem is dynamic since the supply and demand changes contiguously. To find the total surplus over time, the surplus must be calculated and summarized for each time step reflecting the market clearings.

Moreover, different participants on both consumer and supply side also complexifies the surplus calculation as the different participants will have different qualities affecting the surplus. This will be further described in 2.3.1.

Furthermore, physical limitations in the grid often makes it desirable to split the power system in different price regions to deal with congestion. Each area will have independent demand and supply curves and the total surplus must therefore be calculated for each area.

Lastly, it is important to consider the uncertainties in the problem. In the Norwegian power system, the uncertainty regarding reservoir inflow should be considered. This could be done by analyzing different scenarios, assign a probability and find the weighted value of different measures.

Figure 2.4 illustrates a the demand and supply curve describing a power system. As illustrated by the figure, the supply curve includes the marginal costs for wind and hydro power, and the variable thermal costs. The demand curve firstly includes the system losses, shifting the demand curve to the right. Moreover, it includes the export capacity and price, and represents the demand as the consumers willingness to pay for energy. Lastly, the demand curve includes a rationing price, a price cap that represents the cost of non delivered electricity. The area A represents the fixed consumer surplus and area D the consumer surplus from the flexible load. C represents the congestion rent from exporting to a neighboring area and B the cost of losses from the transmission. Moreover, area E, F, G, H and I represents the producer surplus of wind, water and thermal power. The losses represented by E are payd for by consumers by shifting the demand curve. Totally, the producer surplus is represented by area E,F,G,H and I. The Consumer surplus is represented by A and D.

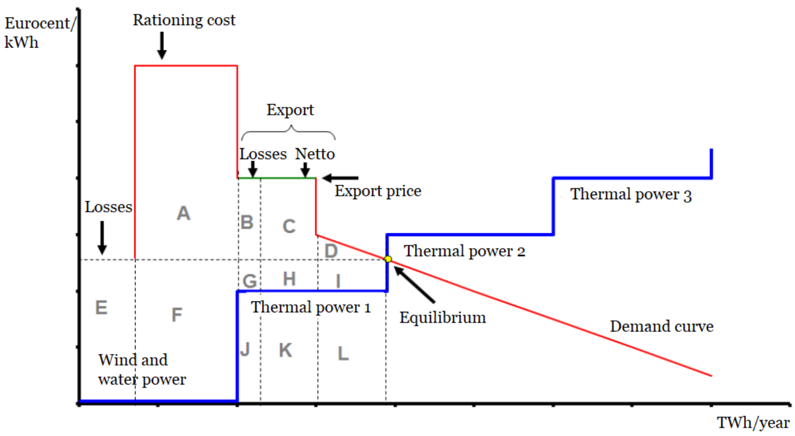


Figure 2.4: Economic surplus in power system (14)

The figure does not include water values, nor import or flooding costs. In a power system, the demand and supply curve should to consist information about the following instances:

Demand curve	Supply curve
Marginal willingness to pay for bidded quantity	Marginal producer costs for bidded quantity
System losses	Water values for hydro power
Import capacity and price	Export capacity and price
Rationing cost	Costs of flooding

Table 2.4: Instances of supply and demand curve

2.3.1 Market participants

Producers

In the Nordic power market, the power producers bid the energy they expect they can deliver and the associated price in the day-ahead market. Since the market power in the Nordic power system is low, the bidded prices correspond with the producers marginal costs. If the producer were to participate in a capacity market as well, the producer would bid in the capacity it could hold back and the corresponding cost. As different types of producers have different traits that needs to be considered when regarding the economic surplus, the following sections will describe the contributions of different producers.

Hydro power:
Even though hydro power in theory has zero marginal costs due to its use of ”free” water inflow, it also has the ability to store water. This leads to an opportunity cost, also known as the water value. This value represents the expected loss in income in the next time step by marginally increasing the release from the reservoir the present time step. A hydro producer will therefore bid it production quantity with corresponding the water value to the market operator. The exception to this is run-of-river hydro producers with no reservoirs. In that case the marginal cost will be close to zero as there is no opportunity costs.

When calculating the producer surplus of a hydro producer the real costs are close to zero. As a result, the producer surplus will equal the market price times the quantity supplied and not subtracted the water value. The market price in a system with only hydro power is illustrated in figure 2.5. The producer surplus in this occasion is represented by the colored area.

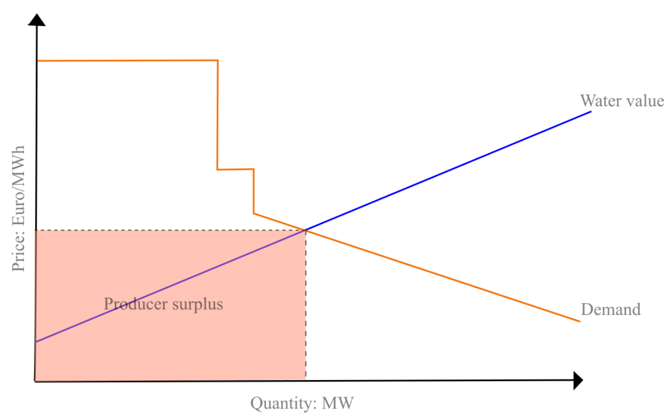


Figure 2.5: Market cross and producer surplus in a power system with only hydro power

Thermal power:
When heat energy is converted to electricity, we have a thermal power plant. Turbines fired with fossil fuel, as gas or coal, and nuclear power plants are examples of such thermal power plants. They are distinguished by marginal costs based on their fuel cost. Furthermore, the cost of -CO_2 emissions highly affects the marginal costs of thermal power and affects the affordability of this technology. Lastly, thermal power plants often have high start-up and shutdown costs that affects whether it will be affordable to run an unit or not. This cost is not included in the marginal cost and is therefore not represented when drawing the market cross. As a result, the area representing the producer surplus does not represent the correct producer surplus. To find the accurate surplus, the startup costs need to be withdrawn.

Wind and solar power:
Since wind and PV has no ability to store its produced output nor uses any fuels, the corresponding marginal costs are close to zero. The producer surplus is therefore represented by the market price times the quantity delivered from wind/PV as describe by area E and F in figure 2.4.

Grid companies

The transmission system operator, TSO, is responsible for managing the national security of the power system. This includes coordinating electricity supply and demand in a manner that unbalances in frequency and power outages. In the Nordic power system, the TSO owns the transmission network and is responsible for the power transfers between areas. Within each areas, there are distribution system operators (DSO), which are responsible for maintaining and operating the power grid on a lower, distribution level.

Since the TSO and DSO only maintain critical infrastructure and insure security of supply, it does have any natural income. The costs of the grid companies is therefore covered by a grid tariff paid by all consumers of electricity and incomes from bottlenecks. How these instances affects the economic surplus is described bellow.

Grid tariff
The main rule when calculating the economic surplus is that all economic effects for all market participants should be included. Financial transactions are normally ignored as they cancelled out in the total welfare. Grid tariffs can be regarded as such financial transaction. As represented by figure 2.6, the grid tariff results in a higher consumer price. The consumer and producer surplus with and without the grid tariff stays the same as the area A + B equals B + C and E stays unchanged. However, the total welfare increases as the area C + D represents the income to the grid company. Often it is interesting to analyze how the surplus distributes, and since the grid tariff neither affects the producer nor consumer surplus, it often can be ignored.

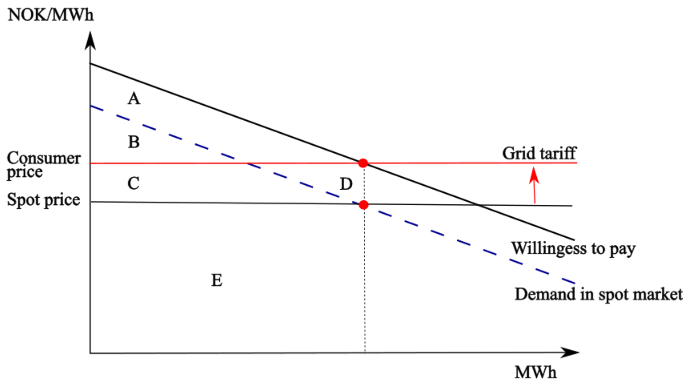


Figure 2.6: Grid tariff and surplus

Exchange between areas and bottlenecks
If a neighboring area has lower area price than the reference area and there is sufficient generation capacity, the surplus area will transfer power to the deficit area. If the transfer capacity is unlimited, the area prices will be equal in both areas. However, if there are transmission limitations, the prices will differ. In the surplus area, the price will decrease, while the price in the deficit area will increase. As a result of the different prices, the grid operator earn a net revenue for the congestion management. The surplus area sells power to the deficit area for a low price, while the deficit area buys the power for a higher price. The income from this exchange is known as the congestion rent and is described by equation 2.1. As there are losses over transmission lines, the TSO must pay for the lost energy as described earlier by area B in figure 2.4.

$$Congestionrent = Q * (p_{deficit} - p_{surplus}) \tag{2.1}$$

where:

Q	Transferred net energy from surplus to deficit area
$p_{deficit}$	Price in deficit area
$p_{surplus}$	Price in surplus area

A graphical representation of the congestion rent is described by figure 2.7 where area A has a lower price than area B. The export capacity is added in the demand curve in area A with the market price in area B and in the supply curve in area B with the market price of area A. As a result of the transferred energy, area A achieves an increased producer surplus(PSA), while area B increases its consumer surplus (CSB). Since the consumers and producers in area A and B respectively not benefits from the exchange, this surplus represents the benefit of the TSO, the congestion rent.

Compared to the situation with no transmission constraints, the congestion rent results in a loss of total welfare as a due to the insufficient transmission capacity. On the other hand, they may be difficult to avoid as the alternative is to increase the transmission capacity which can be costly.

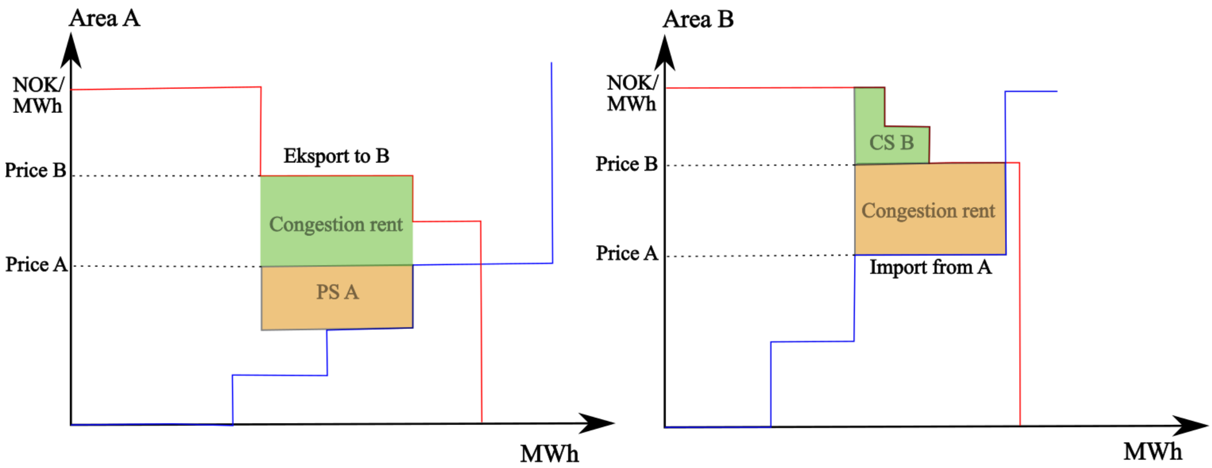


Figure 2.7: Area exchange and economic surplus

Consumers

Consumer flexibility in power systems is defined as the consumers ability to modify its consumption pattern as a reaction to external signals as such as changing power prices. Today, consumers have little incentives to provide such flexibility. Resultingly, the demand is most often considered as firm. The firm load is often represented in the market clearing with the rationing costs. Resultingly, the power prices can become very high as as the load is inelastic. However, with the implementation of new technology as smart meters and controllable loads, consumers may become a significant source of flexibility in the future. As consumers become more aware of power prices they may chose to shift their power consumption towards low price periods, providing flexibility to the power system.

The most accessible source for consumer flexibility today are industry loads. Such loads may chose to shut down their consumption if the price goes over a certain level. In surplus calculations this can be represented as steps in the demand curve representing the quantity they will reduce and the corresponding price.

2.3.2 Reserve procurement

In the balancing markets, it is common to separate between up and down regulation. When effect is reserved for up regulation in balancing markets, it can not be supplied in other power markets unless activated. Resultingly, the energy market will offer less capacity than the case with no reserve procurement. A simplified example of this is illustrated in figure 2.8 where market cross in the energy market is plotted in addition to a up regulating requirement. The supply curve consists of seven generators, sorted after their marginal costs. The demand is represented as price elastic and the illustration does not consider exchange with neighboring areas. When reserving capacity for up regulation, the supply curve is shifted to the left, increasing the power price. Without reservation, the power price would be c_6, but as the requirement is implemented the energy price increase to p_s as generator 5 and 6 must be held out of the market and generator 4 is partly delivering. In this case, the producer surplus increases drastically as the power price increases while the consumer surplus and the total welfare decrease.

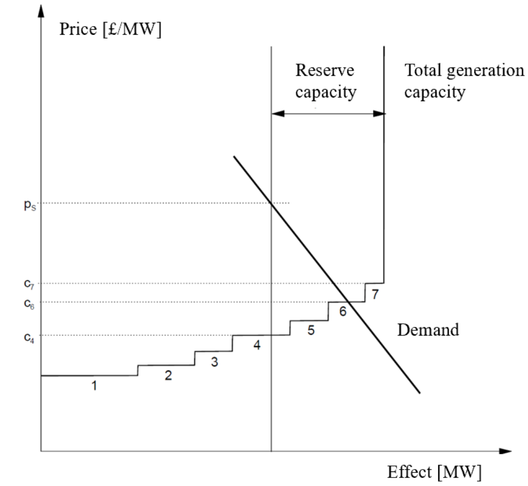


Figure 2.8: Price formation for energy and up-regulating reserves (15)

In the case with down regulation, the effect would be the opposite. Producers are forced to generate energy to be able to down regulate their production if needed. Resultingly, the energy price will decrease due to the increased supply in the system. The producers may get paid a lower price than their marginal costs in the energy market, but will be compensated by the TSO from the reserve market. The producer surplus calculated from the energy market clearing will decrease and the consumer surplus will increase.

In many cases, the power system has sufficient capacity to supply up and down regulation free of charge. An example of such a situation for up regulation is illustrated in figure 2.9. The figure shows that reserves can be supplied free of charge up to until the requirement surpasses P_{RB}.

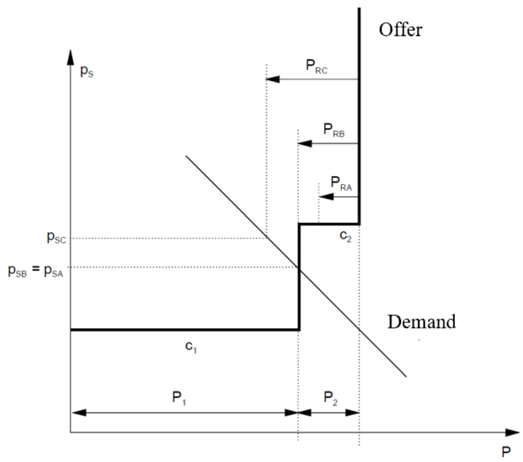


Figure 2.9: Power system with over capacity (15)

Surplus from reserves

The principle of calculating economic surplus is the same as for the energy market. However, in capacity markets, the TSO decides the desired reserve quantity. Resultingly, the demand in such markets are fixed and the market only has one buyer. As there is only one buyer it can be argued whether it is correct to call it a balancing ”market” or not. With only one buyer, the market becomes a monopsoni, however as the market power is strongly regulated on TSO side, the effect can be disregarded (15).

As reserve products are necessary means to ensure the security of supply in the power systems, one does not consider the consumers surplus in the market clearing of the reserve markets. The cost of purchasing reserves will be an expense for the TSO to maintain the instantaneous power balance. As the producers participating in the capacity market will hold back/force production to be able to supply up/down regulation, they will be provided financial incentives to participate. These incentives compensate the producers for their losses and equals the reservation costs. The reservation costs does not directly affect the total surplus since it is an income to the producer and a cost for the TSO. However,as increased reserve procurement for up regulation increase the area price, the consumer surplus will decrease and producer surplus increase. From welfare theory it is known that the maximum total surplus is found when marginal costs equal marginal willingness to pay. Since the market clearing shifts to the left, it is no longer situated where the marginal willingness to pay equals the marginal costs, hence the total surplus decrease. For down regulation, the market clearing is shifted to the right, increasing consumer surplus and decreasing producer surplus. However, the total surplus decrease as the clearing is moved from its optimal point where the total surplus is maximized.

How the market is structured will also affect the surplus in reserve markets. If the reserves is allocated within each price area, economic calculations must be solved for each area, including the effect of transmission of reserve capacity between areas. If the reserves are allocated within an aggregated area, the system does not considers local bottlenecks such as the previous model and can be solved for the aggregated area. This will be further described and tested in chapter 5.

Market participants

As a result of strict terms of delivering balancing services, less power units are able to participate in the balancing markets than in the remaining power markets. Supplying units of reserves must be able to deliver effect and/or energy within a very short time frame. Resultingly, it is here assumed that only dispatchable generation is able to supply reserves as the production must be controllable. Renewable sources as wind and PV is therefore excluded from balancing markets. Moreover, the minimum bid size excludes many small market participants and generating units to deliver flexibility (26).

2.3.3 Challenges

As a result of the uncertainty and complexity in the power system, calculating accurate economic surplus is challenging. The calculation needs to account for; limited consumer elasticity, deviation between water values and actual cost of water, exchange of power between areas, losses and security of supply. Furthermore, the power market consists of many instances depending on each other including intraday, day-ahead and reserve markets. How the surplus of these markets interact and affect each other is not well documented. The markets are well defined, but the fundamental models describing the markets, assume perfect competition and rational market participants. As this is not always the case, the the estimated economic surplus from market models and how it distributes in reality will differ.

2.4 Hydro power scheduling

Loosely defined, the objective of power generation scheduling can be described as ”utilizing available generation resources to satisfy the demand for electricity in such a way that the optimal result is obtained and all relevant constraints are satisfied”(27). To estimate the economic surplus of different measures in a power system, tools for generation scheduling and determining optimal production strategy are necessary. When the optimal strategy is found it can serve as decision support for investments or for bidding into different energy markets. In hydro dominated systems this strategy is determined trough hydro power scheduling.

To obtain the optimal production strategy producers apply optimization models maximizing the total welfare or minimizing producer costs subject to all relevant constraints in the system. For price-taking producers, the marginal cost of production is the optimal price to offer into the market. In theory, hydro power has zero marginal costs due to the ”free inflow”, but it also has the ability to store water in reservoirs. Therefore, the marginal costs of hydro power equals the opportunity costs associated with storing water. This cost is known as the water value and are challenging to achieve. The values are dynamic and depend on uncertain factors as inflow, power price and demand. More information about how to calculate water values can be read in

Furthermore, hydro power scheduling is challenging due to complex system topology and uncertainties in the hydro dominated system. How reservoirs are interconnected in both parallel and series will affect how the production path distributes as well as the individual water values of each reservoir. In addition, the decision in one time step, will limit the choices in in later time steps. To achieve realistic results a production planner needs a detailed description of the system interconnections and water travel time. This increases the amount of constraints in the system and complexifies the optimization problem. Moreover, to decide the optimal production the scheduling model must correctly reflect challenges connected to:

-the system size	-time delays in watercourses	-shared ownership of plants
-uncertainties in input data	-complex topology	-system borders
-time horizon/steps	-coupling of data models	-physical and regulatory constraints

As most systems consist of different types of generation units, the scheduling problem also needs to account for power generation as wind, solar and thermal power. For this reason the optimization is often solved as a mixed hydro-thermal planning problem.

2.4.1 Fundamental modeling

In a fundamental market model, the physical system, comprising generation, transmission and demand, is explicitly modeled. By fundamental optimization we refer to models allowing a detailed representation of the market who are able to reasonably replicate the inner operation of the same market. The technical and economic aspects are often combined and the models normally aim to explain electricity prices from the marginal generation costs.

2.4.2 The scheduling hierarchy

In hydro power scheduling, the decision made today will have an impact several years ahead. The market participant has to consider this impact, at the same time as regarding uncertainty, risk and the complex topology of the hydro system. Different applications require different data models and to achieve realistic models the scheduling problem is often decomposed in smaller, more manageable, sub problems. Traditionally, the problem is split in the following three instances; short term, seasonal and long term scheduling.

Long term scheduling

The objective in long term scheduling is to ensure optimal utilization of the resources in the power system over time and to achieve this the total welfare is maximized. For hydro producers, long term scheduling serves as strategic management of their reservoirs in interaction with the whole power system. Therefore, long therm models are often fundamental, multi-area, stochastic models accounting for the uncertainty in inflow and prices. Depending on the reservoir size, the time horizon is often up to five years. As a result of the long time horizon, long term models tends to simplify the details in the system to avoid immense calculation times. This often includes aggregation, neglecting start-up and shutdown costs of thermal plants and a lack of details reflecting the physical system. Further, it is common that production is represented by discharge curves assuming best point production. Traditionally, the models are solved with a time stage of a week and is therefore not used for detailed production planning, but for investment support and price forecasting. Some existing models used for long term scheduling are, the EMPS model, the FanSi model and ProdRisk.

Seasonal scheduling

Since long therm scheduling lacks in details and short term scheduling requires a high degree of details, an intermediate step to couple the optimization models are necessary. Therefore, the main role of seasonal scheduling is to establish border conditions for models with a shorter time horizon. Normally, the coupling of models is done when the uncertainties are lowest. This means either at the end of the winter, before the snow starts melting or in the autumn, when precipitation starts coming as snow. Moreover, seasonal scheduling is also a tool to forecast reservoir levels, spillage and production such that the producer can minimize its risks and plan maintenance. Seasonal scheduling is based on the same physical system description as long term scheduling, but takes use of different mathematical methods for better valuation of the water in each individual reservoir. Traditionally it is solved with linear programming which includes less uncertainty. Today this is being done with deterministic models whom treat uncertainty trough scenarios. The time horizon for the seasonal model depends on the system characteristics, but is usually 3-18 months with weekly decision stages. Common methods to solve seasonal scheduling problem in the Nordic power system are: the load factor method, multi Scenario Deterministic Optimization and SDDP.

Short term scheduling

The main task of short term scheduling is to provide decision support for market bidding and unit commitment for the coming hours and days. Short term models must therefore include an ”exact” representation of all relevant resources and conditions to result in an implementable operation plan. To describe the detailed heuristics, the scheduling problem is solved with mixed integer programming. Further, the model is usually deterministic, hence pries and inflow are considered as known. Since the boarder conditions are achieved from the seasonal model with a lower degree of detail, it is important that the short term model is flexible enough to account for inaccuracies caused by the different assumptions. The most common model to solve the short term scheduling problem in the Nordic system is the SHOP model.

Chapter 3: PriMod

This thesis takes use of a model under development refereed as PriMod. The model provides a flexible framework for more realistic price forecasting in a hydro-thermal power system. Moreover, the model aims to serve as decision support for long term investments, e.g. related to building new cables abroad and updating and expanding the hydro power system when more capacity is reserved for balancing markets. In the scheduling hierarchy, PriMod solves the same problem as the fundamental long term models, but with more details and a finer time resolution enabling short term optimization. To achieve this, the framework for the model is split in two parts. First, a fundamental long term strategic model provides end-of-horizon valuation of water in hydro storages, water values. Second, the water values from the strategic model are used in a short-term operational model.

The presented methodology consists of a detailed description of how PriMod operates. As the framework of the model is twofold, fist the strategic part will be introduced, then the operational model will be described in detail. This chapter is based on the chapter under the same name from the specialization project.

3.1 The strategic part

The strategic part utilizes a fundamental, long term, hydro-thermal model to solve the scheduling problem and provide valuation of water. As a result of the coupling between reservoirs, the decision made in one time step will affect the decision made in the next. Due to this nature, the scheduling problem is dynamic. Furthermore, the decisions must consider future price and climate dependant uncertainties and resultingly the problem is stochastic. With more than 1000 reservoirs over climatically diverse regions to consider, the Nordic scheduling problem achieves a high dimensionality. Due to this complex nature of the fundamental long term problem, powerful tools are needed to solve it. The most suited models for this task is today the EMPS or the FanSi model. The goal is to provide realistic valuation of water for the operational model using the same data input. This means that the model must describe the expected future cost of water for each time step in the analysis as a function of the hydro storage levels. Since the EMPS and FanSi models have different traits, the next sections will give a brief overview of differences between the two models.

EMPS model uses stochastic dynamic programming and the water value method as described (27) to estimate the water values. To avoid immense calculation times the model aggregates reservoirs, and does not find the individual water value for each reservoir. Then the model performs a re-calibration to insure that the water values are optimal by considering both demand and exchange between areas. Further, the model decides the optimal production for each area before an iterative procedure allocates the optimal dispatch based on heuristics. The EMPS model is the most common model in use for long term hydro-thermal scheduling, it is robust and has shown good results over many years.

FanSi(4) solves the long term problem by splitting the objective function in one deterministic and one stochastic part. It then generates a fan of scenarios to evaluate all possible outcomes and their probability. Further, it minimizes the objective function with subject to the reservoir balance, energy balance and other relevant constraints regarding the physical limitations of the power system. In general, long term fundamental models includes less detailed modeling to avoid immense calculation times and may therefore overestimate the system flexibility. The FanSi model finds the benders decomposition to faster find the optimal decision and to generate the benders cuts, used for the valuation of water in the operational model.

Since the FanSi model does not aggregate reservoirs, it has proved to give more accurate results than the EMPS model. It both reduces the total system spillage and has a higher socioeconomic surplus than the EMPS model (10; 11). However, FanSi has a much higher calculation time and is therefore not yet equipped to replace EMPS. The EMPS model is more efficient and has shown good results over many years and is more adapted for frequent simulations.

3.2 The operational model

As the goal of PriMod is to achieve a more flexible framework for detailed hydro-thermal modeling, the operational model provides an adjustable tool to include a high level of details enabling short term modeling. The operational model takes use of open source Python and the optimization package Pyomo, which makes it easy to add and remove details in the scheduling problem. To calculate the optimal dispatch, the operational model first solves weekly increments. Then it re-optimizes the weekly decision problem with finer time resolution and more details than the strategic model to find the hourly dispatch. The weekly problem is deterministic, considering inflow, demand and power prices as known for each week. Further, the objective is to minimize the system costs associated with the current operation of the decision period and the expected future operating costs. These expected operating costs are given from the valuation of water, provided by the strategic part. After solving a week in the operational model, the reservoir storage levels at the end of the week serve as the reservoir starting point in the next week. Then the re-optimization steps are repeated for all the weeks in the simulation.

Compared to the strategic part whom takes use of existing models, the operational part is a newly built model. The contributions and simulations in this thesis will be executed trough the operational model by adding constraints, details and economic calculations. To achieve a better understanding of these contributions, the next section will provide a detailed description of the model representation.

3.2.1 Model representation

To achieve realistic multi-market price forecasts, PriMod needs to be able to describe the power system with a high degree of detail. The power system is modeled by dividing it into several areas, each consisting of power production and/or consumption. The production includes generation from hydro, thermal, wind and PV, and the consumption is modeled as a mix of firm and flexible demand. In addition, the interconnections and transmission capacities to other areas are described. As illustrated in figure 3.1, the aggregated physical model can combine hydro turbines in series and parallel with thermal production and demand. The next sub chapters will present the theory of the model representation in addition to how the operational model represents each instance. First, the model objective will be presented followed by how generation, demand and the market data is represented.

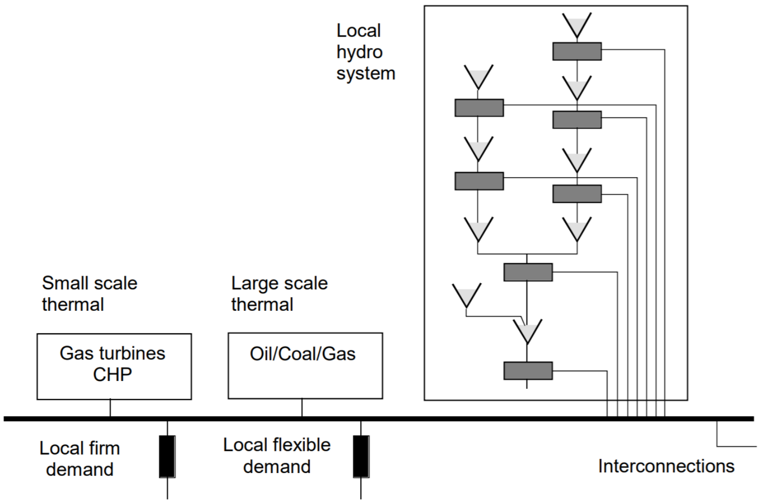


Figure 3.1: Aggregated system model (27)

Objective and power balance

When utilizing optimization techniques, the goal is to achieve the most optimal value of an expression by changing the system variables. If there are physical limitations in the system, the variables must be chosen within the allowed limits. Therefore constraints are included to represent the physical structure of the system.

In the operational model, the problem is solved by minimizing the costs in the power system as shown in equation 3.1. The costs include the marginal cost of thermal production, flexible loads, startup and shutdown costs and the future operational costs connected to the hydrological system. In PriMod, penalties fr spillage and bypass is also included to avoid using hard constraints. These costs are therefore only for modeling purpose and does not reflect the actual system costs.

Minimize:

$$\sum_{a\in\mathscr{A}}(\sum_{k\in\mathscr{K}}\sum_{m\in\mathscr{M}_a} MC_m y_{mk} + \sum_{r\in\mathscr{R}_a} P^S q^S_{rk} + P^B q^B_{rk} + \sum_{p\in\mathscr{P}_a} SC_p \delta_{pk}) + \alpha_{t+1} \tag{3.1}$$

where:

$\mathscr{A}$	Set of areas a
$\mathscr{K}$	Set of time steps k
$\mathscr{M}_a$	Set of market steps, m, within area a
$\mathscr{R}_a$	Set of reservoirs, r, within area a
MC_m	Marginal cost for market step m $[Euro/MW]$
y_{mk}	Exchanged quantity from market step m in time step k $[MW]$
P^s, P^B	Penalty for spillage and bypass $[Euro/m^3]$
q^S_{rk}, q^B_{rk}	Spilled and bypassed volumes from reservoir r in time step k $[m^3]$
SC_p	Startup costs for thermal unit p $[Euro]$
δ_{pk}	Binary variable describing if thermal unit p is shut on in time step k $[0,1]$
α_{t+1}	Future costs of operating the system$[Euro]$

Furthermore, the objective function is subject to many constraints. In power market scheduling, the power balance for each area is the most essential. This constraint states that the sum of production and net exchange must equal the area load. The dual value of this constraint represents the area price. In the operational model, this is represented by equation 3.2. The model also includes constraints regarding reservoir balance, transmission and up/downtime on thermal units. These constraints will be described in more detail later in this chapter.

$$\sum_{r\in\mathscr{R}_a}(W^H_{rk} - W^P_{rk}) + \sum_{m\in\mathscr{M}_a} y_{mk} + \sum_{b\in\mathscr{A}}(tr_{abk}(1 - tr^{loss}_{ab}) - tr_{bak})) = D_{ak} - \sum_{wp\in\mathscr{W}_a} W^W_{wpk} \quad (3.2)$$
$$\forall a, k \in \mathscr{A}, \mathscr{K}$$

where:

$\mathscr{R}_a$	Set of reservoirs, r, within area a
$\mathscr{W}_a$	Set of wind/PV parks, wp, within area a
$\mathscr{M}_a$	Set of market steps, m, within area a
W^H_{rk}, W^P_{rk}	Produced and pumped energy from reservoir r in time step k $[MW]$
y_{mk}	exchanged quantity from market step m in time step k $[MW]$
tr_{abk}	exchanged energy from area a to area b in time step k $[MW]$
tr^{loss}_{ab}	transmission loss between area a and b $[fraction(0,1)]$
D_{ak}	Demand in area a in time step k $[MW]$
W^W_{wpk}	produced energy from wind/PV park wp in time step k $[MW]$

Hydro representation

As mentioned in the chapter about hydro power scheduling, the modeling of hydro power is a complicated task due to the complex system topology and many uncertainties. To describe the hydro power system, the reservoirs and stations are defined as interconnected modules in parallels and series. As illustrated by figure 3.2, a module typically consists of a reservoir, a station/plant and waterways for spillage, bypassing and discharge. The inflow to the reservoir is either storable or non-storable. The storable inflow is what you can save for later in a reservoir, while the non-storable inflow represents water that has to pass by the station or be bypassed. If the total inflow is bigger than the discharge capacity, the water is spilled. To correctly model hydro power, reservoirs, plants, waterways/topology and the associated restrictions needs to be represented. As shown in 3.1, the hydro power system can include several modules, where they can either be coupled in strings or in parallels, correctly modeling of the complex interconnections is therefore crucial.

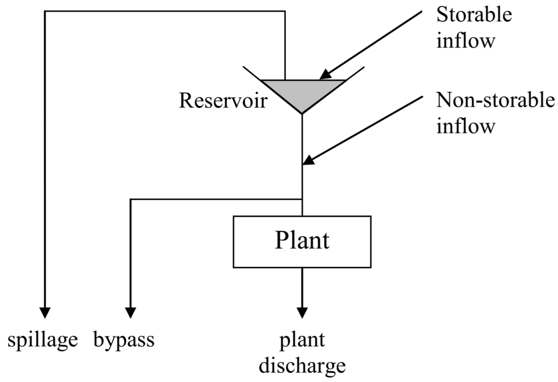


Figure 3.2: Hydro power module (27)

Reservoir

As the managing of reservoirs determines all other output variables, reservoir size must be specified for all modules. If a module has no storable inflow, for example a run-of-river plant , the reservoir size is set close to zero. Moreover, the total power output of a series of modules increase with the water column above the generators. This relationship can be described with piecewise linear curves describing the coupling between the water level and the volume. The backwater level is the level of the reservoir downstream of the plant and the level increase with discharge and decrease the power production. If the reservoir curve is specified with the backwater level, it is possible to determine the plant head. As a result, the calculated production will depend on the backwater and reservoir level. This makes is possible to optimize the plant head, calculate power consumption of pumps(depends on the pump head) and production. Furthermore, the reservoir level is often regulated due to environmental constraints. Therefore models needed to add constraints describing the maximum and minimum allowed reservoir level. In Norway, reservoir limitations are set by NVE.

In PriMod, information about the reservoir capacity and minimum reservoir level is given. Constraints regarding the both regulated and unregulated reservoir balances makes sure the system is in equilibrium. These constraints are described by equation 3.3 and 3.4 respectively. The first equation states that the difference in reservoir level, x_{rk} from one time step, k, to another (in each reservoir r), plus released, bypassed and spilled water from the reservoir, minus the discharged, bypassed, spilled and pumped volumes from upper reservoirs must equal the regulated inflow. Further, the second equation states that the sum of release trough all segments in the station, q^{D}_{nrk} and the bypassed volume q^{B}_{rk} minus minus the actual release q^{R}_{rk} must equal the unregulated inflow I^{ureg}_{rk}. The dual value of those constraints, represents the water value by increasing the discharge of one unit. In the objective function, penalties for both bypass and spillage of water are defined. Resultingly, spillage and bypass will only occur to avoid breaking constraints or to fill up the reservoirs more economically.

$$x_{rk} - x_{r,k-1} + q_{rk}^{R} + q_{rk}^{S} + q_{rk}^{P} - \sum_{i \in \mathscr{R}_{up}} (\sum_{n \in \mathscr{N}_i} q_{nik}^{D} + q_{ik}^{B} + q_{ik}^{S} + q_{ik}^{P}) = I_{rk}^{reg} \qquad \forall k, r \in \mathscr{K}, \mathscr{R} \tag{3.3}$$

$$\sum_{n \in \mathscr{N}_r} q_{nrk}^{D} + q_{rk}^{B} - q_{rk}^{R} = I_{rk}^{ureg} \qquad \forall k, r \in \mathscr{K}, \mathscr{R} \tag{3.4}$$

where:

$\mathscr{R}$	Set of reservoirs/modules r
$\mathscr{R}_{up}$	Set of upstream reservoirs i
$\mathscr{N}$	Set of discharge segments from reservoirs
x_{rk}	Reservoir volume in time step k $[m^3]$
$q_{rk}^{R/S/P}$	Released, Spilled or Pumped volume from reservoir r in time step k $[m^3]$
q_{nik}^{D}	Discharged volume to reservoir r in time step k trough segment n from reservoir i $[m^3]$
$q_{ik}^{B/S/P}$	Bypassed, Spilled or Pumped volume to reservoir r in time step k from reservoir i $[m^3]$
I_{rk}^{reg}	Regulated inflow to reservoir r in time step k $[m^3]$
I_{rk}^{ureg}	Unregulated inflow to module r in time step k $[m^3]$

Plant

To describe a hydro power plant, the discharge capacity m^3/s and its average energy equivalent in kWh/m^3 is crucial. The energy equivalent quantifies how much energy is stored in the reservoir and is calculated by equation 3.5. In reality, the plant efficiency will depend on the discharge and plant head. Therefore the module efficiency will change as a function of discharge and head. Moreover, modules often consist of several turbines. However, turbines are often considered as one entity for simplification, resulting in a non linear relation between turbine discharge and output. When modeling a hydro power plant, restrictions connected to maximum and minimum production capacity also have to be included.

$$e = \frac{\lambda \cdot g \cdot H \cdot \eta}{3.6 \cdot 10^6} \tag{3.5}$$

where:

λ	Water density $[kg/m^3]$
g	Gravity $[m/s^2]$
H	Plant head $[m]$
η	plant efficiency

In PriMod, each module has a number of linear PQ segments representing the output effect as a function of its discharge, q_{rk}^{D} in m^3/s, energy equivalent, η in $MW/m^3/s$ and relative head, H. The plant production W^H is calculated by equation 3.6. Since the energy equivalent is a function of the system head, and the head is dependent on the reservoir level, the relative head is supposed to account for this change. However, in PriMod, the relative head only refers to the initial reservoir level and does not account for future changes in reservoir not backwater level. Regarding maximum production capacity, PriMod includes constraints to how much discharge each segment is allowed to dispatch. The plant production can be described by equation 3.6 and is included inn the energy balance. The discharge is regarded as a decision variable and is included in the reservoir balance. The dual value of the plant production also reflects the individual water value each reservoir has per unit increased production.

$$W^H = \sum_{n \in \mathscr{N}_r} H_r \eta_{nr} q_{nr}^D \quad \forall r \in \mathscr{R} \tag{3.6}$$

where:

W^H	Plant production $[MW]$
$\mathscr{N}$	Set of discharge segments from r
H_r	Relative head$[0, 1]$
q_{nr}^D	Discharge trough segment n from reservoir r $[m^3]$
η_{nr}	Energy equivalent $MW/m^3/s$

Topology

The system topology describes how the modules are connected. The destination for discharge, bypass and spillage is not necessarily equal and must therefore be specified. This task can become very complicated when handling cascades river system with many interconnected modules. Hard restrictions or penalties can be included to describe minimal/maximal bypass and discharge and spillage.

PriMod represents the system topology by defining all the interconnected modules/reservoirs. This representation is essential in the regulated reservoir balance in equation 3.3 where inflow and release to connected reservoirs are expressed.

Pumping

Water can be moved upstream from a reservoir trough a pump. With pumps, water can be used to generate power during peak periods with high prices and pumped back in the reservoir during non-peak hours when the market price is low. This is more common in thermal systems with limited generation capacity. In Norway, pumping is moreover used to improve the total utilization of water. Pumping is modeled trough a linear relation between the pump head and the maximum pumping capacity. It is often separated between reversible pumps, where the pump can be used for both generation and pumping, and pumping plants used to move water from one reservoir to another. When modeling pumps, information about pump efficiency, head and capacity is needed.

The operational model explicitly describes what reservoirs have pumps connected to them and where the water is pumped. Further, it defines the consumed pumping power for each reservoir and the maximum pumping capacity. The pumping discharge is one of the decision variables and is included in both the reservoir and energy balance. Losses in the pump is neglected and start/stop costs and ramping are not accounted for.

Valuation of water
The water values represents the expected loss in income in the next time step by marginally increasing the release from the reservoir the present time step. In PriMod, this values are achieved trough the strategic part and serves as data input in the operational model. One way to achieve the correct values is by generating the benders cuts. In that case equation 3.7 will be added as a constraint in the model. This represents a set of weekly benders cuts determining the expected future costs, e g the profit of the power producers. The constraint 3.7 states that the future cost, minus the water value times reservoir level is bigger than the cut coefficient. If there are several reservoirs, the cuts become multidimensional. In other words, the cuts provide a function determining the expected future costs by evaluating the water as a function of the reservoir level. This future costs are included in the objective function. To consider the individual water value for each reservoir per time step, either the dual value of the reservoir balance or the production rule can be regarded. These dual values will provide how much the objective function changes per increased unit released volume $[m^3]$ or increased effect [Watt].

$$\alpha_{t+1} - \sum_{a \in \mathscr{A}} \sum_{r \in \mathscr{R}_a^{reg}} \pi_{arc} x_{ark} \geq \beta_c \quad k = |\mathscr{K}| \ \ \forall c \ \in \mathscr{C} \tag{3.7}$$

where:

$\mathscr{A}$	Set of areas a
$\mathscr{R}_a^{Reg}$	Set of regulated reservoirs in area a
$\mathscr{C}$	Set benders cuts c
α_{t+1}	Expected costs in next time step $[Euro]$
π_{arc}	water value for reservoir r in area a for cut c $[Euro/m^3]$
x_{arc}	reservoir level in reservoir r, in area a, in time step k $[m^3]$
β_c	Benders cut c $[Euro]$

Thermal representation

In a mixed hydro-thermal system, the thermal power generation is represented by its marginal costs and maximum capacity. The marginal costs include the fuel costs and variable maintenance costs. The costs of emission may also be included. In general, a thermal power plant will run if the thermal marginal costs are lower than the system marginal costs. In some cases with nuclear power or contracted thermal plants, some generation will be run and paid for regardless of the market price. In such cases the plants can either be modeled with zero marginal costs, or model the plant as a fixed contractual purchase right. In the last case, the variable costs will be taken into account when deciding the dispatch of the problem. Startup and shutdown costs reflect the additional cost of starting and stopping an unit. These costs significantly influence the way thermal systems are operated and ignoring them would lead to unrealistic results. Table 3.1 shows average running costs and start/stop costs for different thermal units. To model start- and stop costs, MIP programming or linear approximations can be used.
To model thermal power, PriMod defines a set of market steps representing the marginal costs of different thermal units and their associated capacity. The costs representing the thermal generation is included in the objective function. Furthermore, startup/shutdown(SCs) costs, and minimum up/down time is introduced to achieve more realistic modeling. To achieve this problem is formulated as mixed integer programming(MIP). The SCs are included in the objective

Type	Capacity [MW]	Running costs [€/MWh]	Startup cost[€]	Shutdown costs [€]
Lignite	516	5	19172	2876
Nuclear	1097	9	-	-
Hard coal	469	26	12291	1842
Gas	387	47	5048	505
Oil	280	95	10863	1086

Table 3.1: Average costs for thermal units (6)

function together with a binary variable reflecting if the thermal unit is shut on of of that in the associated time step.

Wind and PV representation

Since the marginal costs for wind and PV production are zero and because it is not possible to store, it is preferred to produce whenever the wind is blowing and the sun is shining. Wind generation is determined by the velocity of wind, and PV by the solar radiation which in reality are a stochastic parameters. For simplification purposes, the deterministic equivalent is often used to avoid long calculation time. When modeling, it should be considered if the wind and PV should be modeled as deterministic or stochastic.

In PriMod, the coding represents wind and PV power as deterministic value for each area. The wind and PV power is given in MW and is not a function of wind speed nor solar radiation. The energy is then subtracted from the demand in the power balance. Since wind and PV has zero marginal costs it is not included in the objective function.

Demand representation

The aggregated loads in the power system determines the demand. Demand can be modeled as firm or price elastic. Firm demand is the typical way to model most demand from the industrial, service and domestic sector and is considered inelastic in short term. In short term, electricity prices normally have been fixed and therefore is almost all demand traditionally modeled as firm. As a result, the only way to decrease the demand is trough rationing. Demand side management is usually not modeled in the existing models, leading to an underestimation of the system flexibility. Firm demand is represented by quantity and profile within time step.The price elastic demand is dependent on the market price, whereas a high market price will reduce the price elastic demand. The modeling of price elastic demand is similar to the thermal modeling and is represented by a quantity and a price. In figure 3.3 the firm demand is 62,3 % and the price elastic demand equals 37,7 % of the total demand. From the figure it is clear that the price elastic demand is dependent of the market price.

For each time step, PriMod receives information about the aggregated load for each area. In the market data, rationing, price sensitive loads are represented with their marginal cost and capacity. The resulting demand curve will therefore consist of firm demand and the price sensitive loads. The load is represented trough a demand profile from the data input. Further, the energy balance makes sure the aggregated load covered for each area.

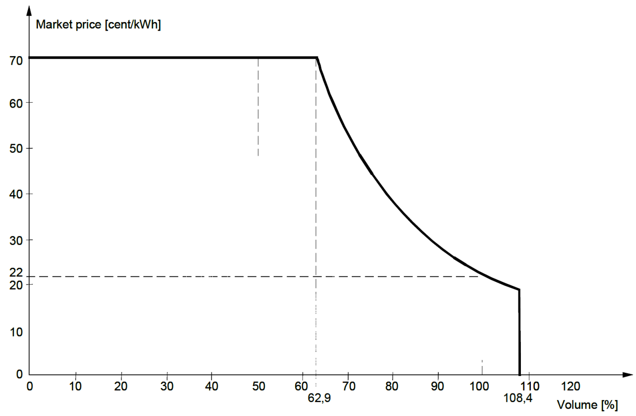


Figure 3.3: Demand profile for a time step (27)

Grid data

Necessary grid data to be included in the modeling of a multi area, hydro-thermal power market are how the areas are connected together. This includes transmission capacities in each direction, linear or piecewise linear energy losses and transmission fees. Transmission capacities can vary during the day and may lead to invalid results if not modeled correctly.

In PriMod the grid data represents transmission capacities and losses. The losses are given as a fraction for each interconnection. Multiplying the fraction with the transmission between each area gives the total loss with is included in the energy balance. Further, the transmission between areas are bound by their respective transmission capacity for each time step.

Area exchange and exogenous markets

When regarding fundamental market models, the power system has to be regarded as a whole. If the price is lower in a neighboring area, it will be desirable to purchase this energy. The same goes for exchange with exogenous markets. If there are cables built abroad, the cable capacities and exogenous prices must be given to determine the exchange between the areas. For more realistic modeling of the power system, ramping constraints should be included such that a cable not monumentally can turn from full import to full export or vice versa. One should also consider how the load flow is represented, either trough the ATC approach or through flow based market coupling.

In PriMod, interconnection between all areas are defined with transmission capacity in both directions and the associated loss fraction. It can also see exchange with exogenous markets as a market step in each area defined with transmission capacity and a price series. Furthermore, PriMod includes cable ramping by limiting how fast the the transferred energy can change from one time step to an other. This is expressed in equation 3.8.

$$-\Delta TR^{lim} \leq (tr_{abk} - tr_{bak}) - (tr_{ab(k-1)} - tr_{ba(k-1)}) \leq \Delta TR^{lim} \qquad \forall\ a, b, k \in \mathscr{A}, \mathscr{A}, \mathscr{K} \tag{3.8}$$

where:

$\mathscr{A}$	Set of areas a
$\mathscr{K}$	Set of time steps k
ΔTR^{lim}	Ramping limit $[MW/h]$
tr_{abk}	Transmission from area a to area b in time step k $[MW]$

3.3 Economic calculation

One of the contributions in this thesis is the implementation of an algorithm for surplus calculations. To achieve this, a new result file had to be constructed with all the relevant information regarding marginal prices, water values, traded capacities, startup costs. The file is structured as described by figure 3.4.

Area

-**Local values:**
-area price, load, area reserve price, reserve requirement
-**Generation units**
- production, capacity, marginal price/water value, startupcost
-**Reserve units**
- reserve price, reserve capacity
-**Exchange with area**
- exchanged capacity, exchange price

Figure 3.4: Structure of constructed result file

Price cross

After constructing the result file, an algorithm loops trough each generation, load and exchange unit and adds the price and capacity in a list for offer or demand for each area. All supply from generation and import is added to the offer list while demand from load and export is added to the demand list. After this the offer list in sorted after the steps marginal price in increasing order and the demand is sorted in decreasing order. Lastly,a function loops trough all elements in the lists and plots the offer and demand to obtain the market cross. Furthermore, a marker is added to separate the different types of production and demand for graphical purposes. Figure 3.5 shows an example of a market cross for an area in a given time step. The pink line represents the marginal price where the supply and demand curve intersect. The different colors represent different types of supply and demand elements as described by table 3.2

Supply type	Colour	Demand type	Color
Wind and PV	Green	Fixed load	Black
Hydro power	Blue	Flexible load	Purple
Thermal units	Red	Export	Yellow
Import	Orange		

Table 3.2: Colors of the different types of supply and demand

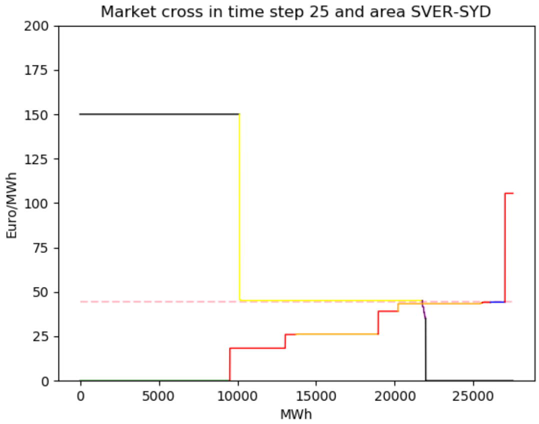


Figure 3.5: Example of generated market cross at a given area and time step

Surplus calculations

Total surplus

As the power market is cleared for each price area and time step in the simulations, the economic surplus must be calculated for each market clearing. This means, that to find the total surplus, the surplus calculations must sum the surpluses for each area and time step in the analysis. In addition, the surplus must be multiplied with the length of the time step to achieve the accurate value. The sum of the total surplus is represented by equation 3.9. The system losses are ignored as PriMod does not account for internal losses in the power system.

$$TS = \sum_{k \in K} \sum_{a \in A} (PSE_{ak} + CS_{ak} + CR_{ak}) * T_k \tag{3.9}$$

where:

$\mathscr{A}$	Set of areas a
$\mathscr{K}$	Set of time steps k
PSE_{ak}	Producer surplus from the energy market in area a, time step k [€]
CS_{ak}	Consumer surplus in area a, time step k [€]
CR_{ak}	Congestion rent in area a, time step k [€]
T_k	Length of time step k [h]

Producer surplus

For all the market steps with generating units (e.g. all supply steps except the import steps), the producer surplus is calculated by multiplying the production with the difference between the area price and the marginal price. If a thermal unit is turned on in a time step, the startupcost will be subtracted in that period. Equation 3.10 and describes how the producer surplus is calculated in the energy market. Do note that if power is generated from wind or PV, the marginal price is set to zero. For hydro power, the marginal costs are set to the water value to account for the future costs in the system. In reality, the marginal cost of hydro power is zero, but as this thesis only analyses a short time period, the water values are applied to compensate for the future costs of water.

$$PSE_{ak} = \sum_{i \in \mathscr{I}_a^{gen}} (p_{ak} - mc_{ik}) * q_{ik} - sc_{ak} \tag{3.10}$$

where:

$\mathscr{I}_a^{gen}$	Set of generating units i in area a
p_{ak}	Area price in area a, time step k [€/MWh]
mc_{ik}	marginal price of generating unit i in time step k [€/MWh]
q_{ik}	produced quantity from generator i in time step k [MWh/h]
sc_{ak}	Startup costs in area a in time step k [€]

Reservation costs

Equation 3.11 describes how the cost from reserve procurement is calculated. For all the units defined to supply reserves, the reserved quantity is multiplied with the reserve price. Since the producers only are paid for the reservation of capacity, the marginal costs are not subtracted. The first sum in the equation represents the costs of up-regulation, while the second sum represents the costs of down regulation. When a producer holds back/force capacity in balancing markets, they lose profit. The reservation cost therefore the economic compensation incentiveizing the producer participate in balancing markets. Since reservation costs is an income for the producer and an expense for the TSO, it is not included in the total surplus in equation 3.9.

$$PSR_{ak} = \sum_{i \in \mathscr{I}_a^{UP}} (p_{ak}^{UP} * q_{ik}^{UP}) + \sum_{i \in \mathscr{I}_a^{DOWN}} (p_{ak}^{DOWN} * q_{ik}^{DOWN}) \tag{3.11}$$

where:

$\mathscr{I}_a^{UP/DOWN}$	Set of units for UP/DOWN regulation i in a area a
$p_{ak}^{UP/DOWN}$	Up/down regulating price in area a in time step k [€/MW]
$q_{ik}^{UP/DOWN}$	Reserved quantity from generator i in time step k [MW/h]

Consumer surplus
To calculate the consumer surplus, the rationing price and fixed load must be known. Moreover, all flexible loads must be quantified. Equation 3.12 represents how the consumer surplus is calculated for area a, in time step k. In this thesis, the rationing price is set to 400 €/MWh. The consumer surplus does not represent a physical income for the consumers, it is moreover a measurement to compare the consumer benefit of different implementations. In this thesis, the consumer surplus is relative to the rationing price.

$$CS_{ak} = \sum_{i \in \mathscr{I}_a^{load}} (mc_{ik} - p_{ak}) * q_{ik}^{load} + (R - p_{ak}) * q_{ak}^{L} \tag{3.12}$$

where:

$\mathscr{I}_a^{load}$	Set of flexible loads i in area a
mc_{ik}	Marginal price of element i at time step k [€/MWh]
q_{ik}^{load}	Traded consumer flexibility i in time step k [MWh/h]
R	Rationing price [€/MWh]
q_{ak}^{L}	Firm load in area a [MWh/h]

Congestion rent
If areas exchange power, a congestion rent is imposed by the TSO for congestion management. As described in chapter 2.3.1 this can be represented either by the area between the export price and the area price or the area between the area price and the import price. To avoid double calculation of the congestion rent and include exchange losses, this thesis defines the congestion rent as the difference between the import price and area price times the quantity exchanged. The import price is equal to the area price in the area exporting power. In reality, the congestion rent is an income to the TSO for transferring power from a surplus area to a deficit area. If prices are equal, this income is zero. Equation 3.13 states how the congestion rent is calculated.

$$CR_{ak} = \sum_{i \in \mathscr{I}_a^{imp}} (p_{ak} - p_{ik}^{imp}) * q_{ik}^{imp} \tag{3.13}$$

where:

$\mathscr{I}_a^{imp}$	Set of import steps in area a [€/MWh]
p_{ak}	Area price in area a, in time step k [€/MWh]
p_{ik}^{imp}	Import price from market step i, in time step k [€/MWh]
q_{ik}^{imp}	Imported quantity in from step i in time step k [MWh/h]

Chapter 4: Data input

This thesis takes use of the HydroCen WP 3.1 low emission scenario, provided by SINTEF Energy Research. HydroCen is the Norwegian center of Hydro power technology, working towards enabling the Nordic hydropower sector to meet complex challenges and exploit new opportunities trough innovative technology. The dataset is developed to show and quantify variations in power prices in Northern Europe in 2030. Particularly to understand how developments in the power system influence the market. HydroCen represents both a reference case and a low emission scenario. The reference case is a realistic base scenario for 2030 and represents a collection of moderate assumptions based on the visions of ENTSO-e. As new ambitious targets are set, the low emission scenario aims to reflects this. Therefore low emission case includes a higher share of renewable energy, increased transmission capacities and a reduction in energy from fossil sources. This chapter is based on the reports of the HydroCen dataset presented in *HydroCen Reference Scenario: documentation and assumptions* (28) and the report *Power price scenarios: results from the reference scenario and the low emission scenario* (29)

This chapter will describe the data input from the HydroCen WP 3.1 low emission scenario including information about generation with a detailed description of the hydro system, market data and exchange capacities.

4.1 Price zones

The low emission scenario and the reference case includes the same price zones. They consist of 57 interconnected price areas as described in figure 4.1 and table 4.1. 24 of the 57 areas are of shore wind parks, represented by the elliptic areas in the figure. The areas represented by rectangles are price zones consisting of both load and generation. The exception to this is area 13 and 14 which only consists of generation from hydro power.

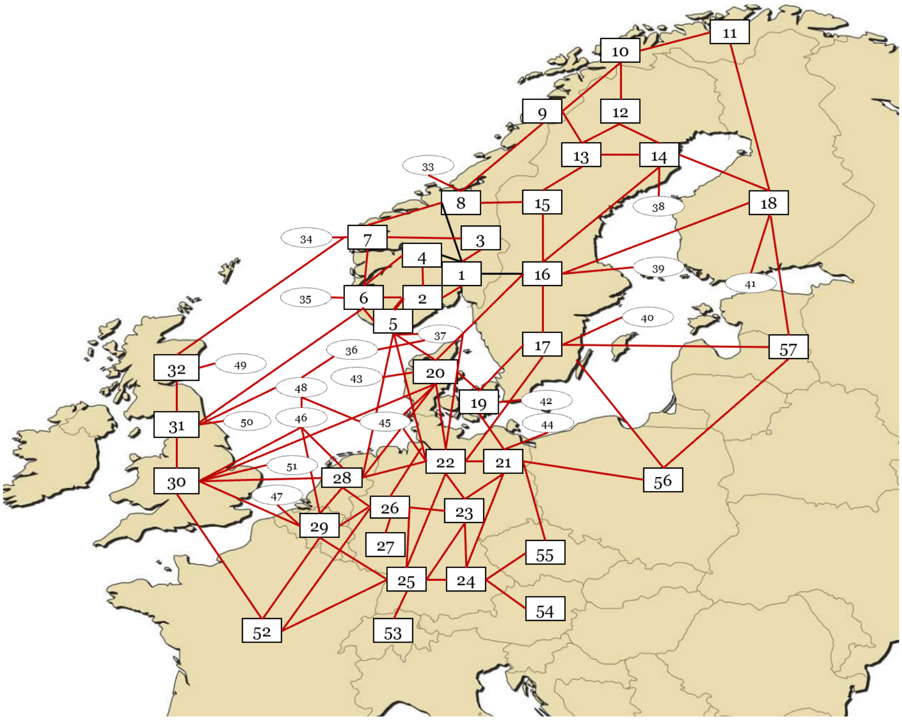


Figure 4.1: Areas and connections in the HydroCen dataset

Area	Nr.	Area	Nr.	Area	Nr.
Ostland	1	Danm-vest	20	Sver-m-owp	39
Sorost	2	Tysk-ost	21	Sver-s-owp	40
Hallingdal	3	Tysk-nord	22	Fi-owp	41
Telemark	4	Tysk-midt	23	Danm-o-owp	42
Sorland	5	Tysk-syd	24	Danm-v-owp	43
Vestsyd	6	Tysk-svest	25	Tysk-o-owp	44
Vestmidt	7	Tysk-vest	26	Tysk-v-owp	45
Norgemidt	8	Tysk-ivest	27	Nederl-owp	46
Helgeland	9	Nederland	28	Belgia-owp	47
Troms	10	Belgia	29	Doggerbank	48
Finnmark	11	GB-south	30	GB-n-owp	49
Sver-on1	12	GB-mid	31	GB-m-owp	50
Sver-on2	13	GB-north	32	GB-s-owp	51
Sver-nn1	14	Norgem-owp	33	Frankrike	52
Sver-nn2	15	Vestmi-owp	34	Sveits	53
Sver-midt	16	Vestst-owp	35	Osterrike	54
Sver-syd	17	Sorlan-owp	36	Tsjekkia	55
Finland	18	Aegir-owp	37	Polen	56
Danm-ost	19	Sver-n-owp	38	Baltic	57

Table 4.1: Area names and numbers

4.2 Generation

The areas in the HydroCen dataset covers its loads by generating energy from hydro, thermal, solar or wind power units. The total installed generation capacity is represented in figure 4.2. The thermal sources, nuclear, gas, coal and oil still stands for the largest share of installed generation capacity, representing 56 % of installed capacity. The installed capacity from renewable energy from wind, PV, bio and hydro power has increased to 41 %, in line with the ambitious climate targets the EU has set for 2030. More detailed information about the data input associated with each generation source will be described in the following sections.

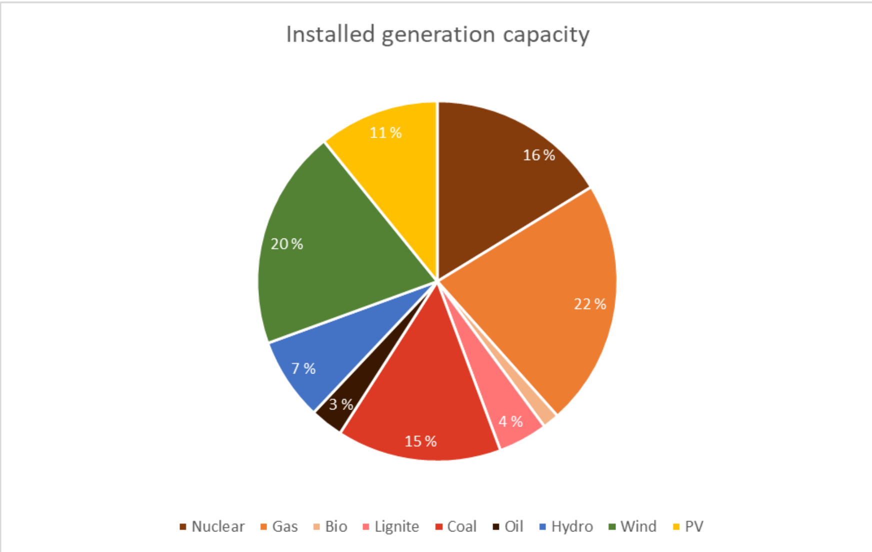
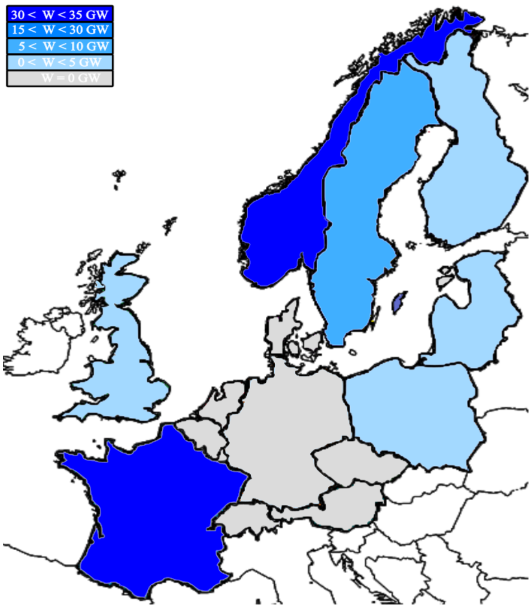


Figure 4.2: Total generation capacity

4.2.1 Hydro power

In the dataset, 24 of the 57 areas consist of hydro power. Figure 4.2 illustrates the installed hydro power capacity in each country. However, do notice that these countries again are divided into price area as described by figure 4.1. The Nordic power system, containing Norway, Sweden and Finland, consists of 1087 hydro power modules. In the the remaining hydro areas in the dataset, the hydro power is represented with one aggregated hydro module per area. Detailed data input regarding the necessary topology, parameters and historical data will be described in the next sections.



Country	Hydro capacity $[GW]$
Norway	31.4
France	31.6
Sweden	16.3
Polen	3.7
Finland	2.4
Baltikum	2.6
UK	1.2

Table 4.2: Installed hydro capacity per country

Topology

In Norway, Sweden and Finland, the hydro power modeling is based on the physical system. For each price area within these countries the hydro modeling holds a high degree of detail. All the reservoir destinations are explicitly defined, including the waterways of release, spillage, bypass and pumping. An example of this is shown in figure 4.3. The figure shows the cascaded reservoirs in the Sauda watercourse and the destination of the different waterways. If the arrow between reservoirs is green, spillage, bypass and release has the same destination. An orange arrow represents bypass and spillage and the blue arrows represent release.

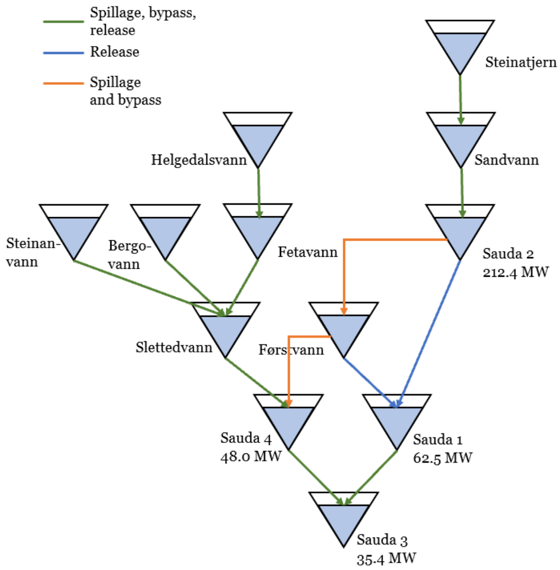


Figure 4.3: Interconnected reservoirs

Inflow

The HydroCen dataset includes the historical inflow for each reservoir in Norway, Sweden and Finland from 1962 to 1990. The inflow is represented with a weekly time resolution.

Water values

The water values are achieved by running a long term fundamental model on the same data input as used on the operational model as described by chapter 3. In this thesis the HydroCen dataset is run the FanSi model to generate the benders cuts for valuation of water. FanSi is run with the data input as described in this chapter.

Parameters

For each module in the system, the HydoCen dataset includes the following parameters:

-Maximal reservoir	-Minimal reservoir	-Owner share
-Maximal bypass	-Nominal head	-Tail water level
-Max regulated inflow	- Max unregulated inflow	-Regulation level
-Maximal flow	-Maximal production	-Conversion factor
-Average inflow	-Scaling factor	-Module name
-Pump capacity	-Module ID	-Module connections

Furthermore, the dataset includes a set of PQ-curves for each reservoir representing the production as a function of discharge.

4.2.2 Wind and solar power

As the data is set to reflect the most ambitious climate targets, wind generation becomes the second largest power producing technology in 2030. The installed capacity of wind is taken from the EUCO30 Scenario (30) and then adjusted upwards to account for more ambitious climate targets in the low emission scenario (29). Table 4.3 depict the installed capacity if wind av PV power per country in the low emission scenario.
To include wind and PV power, the HydroCen dataset provides data based on historical wind series and solar radiation. The series represent the quantity produced in each wind/PV park between 1958 and 2015 with an hourly time resolution. Of the 56 areas in the dataset, all areas except one include wind generation. Further, 24 of the areas are of-shore wind parks which consist only of wind generation and cables for exchange. These areas are shown as circles in figure 4.1.

Country	Wind capacity $[GW]$	PV capacity $[GW]$
Norway	8.05	1.23
Germany	78.89	69.6
Sweden	18.61	1.37
Great Britain	38.60	19.46
Finland	4.27	0.54
Netherlands	12.53	8.23
Denmark	14.55	1.19
Belgium	12.00	5.50
Baltic	2.35	0.05
Poland	15.90	0.90
France	27.96	22.29
Switzerland	1.55	0.00
Austria	2.86	0.00
Czech republic	2.95	0.00
Total	237.37	130.35

Table 4.3: Installed wind capacity in the HydroCen low emission scenario

4.2.3 Thermal power

As the low emission scenario aims to reflect ambitious climate targets, thermal production is reduces significantly compared to the reference scenario. It assumes that all power production from lignite is faced out and a further reduction of power production of the remaining fossil sources. No new nuclear investments are assumed before 2030. In addition are four nuclear power plants situated in Sweden assumed decommissioned by 2030, representing a reduced net effect of 2.8 GW.

Fuel prices for thermal generation is expected to set the power price for most hours in 2030 and is therefore important to forecast correctly. These prices have large variations and are impacted by many factors such as economic growth, political stability and oil prices. The creators of HydroCen emphasizes that their assumptions are based on available data and reports. The fuel prices levels are primarily based on analyzes conducted by NVE and IEA (31)(32). The assumed fuel prices are given in table 4.4 bellow. Furthermore, the HydoCen dataset assumes that the trend of increasing CO2 price will continue and sets the CO2 price to 30 Euro/t in 2030. Lastly, the dataset includes shutdown and start-up costs for all thermal units.

Type	Marginal price
Coal	70 \$/MWh
Gas	20 €/MWh
Bio	8.6 €/MWh
CO_2	30 €/t

Table 4.4: Fuel prices (28)

4.3 Market data

4.3.1 Demand

Towards 2030 the demand is expected to grow as a result of an increased population, growth in industry and electrification of the transport and heat sector. The HydroCen dataset increases the total demand based on the market analysis of NVE (31) as shown in table 4.5.

Country	NVE 2030 $[TWh]$	Growth	2016 $[TWh]$
Norway	146	10 %	133.2
Sweden	142	2 %	139.8
Finland	93	8 %	85.0
Denmark	43	24 %	34.7
Germany	575.82	5 %	548.4
Netherlands	120.23	5 %	114.5
Belgium	88.41	5 %	84.2
Great Britain	350.7	5 %	334.0

Table 4.5: Yearly load assumptions from NVE's power market analysis of 2030 compared to historical load inn 2016 (31)

4.3.2 Flexibility

It is expected that demand response and smart distribution of load will affect the load profiles toward 2030. However, as the dataset is designed to fit models with no formal optimization within the week, optimal usage of short-term storages are therefore ignored. Resultingly, modeling of demand-side response is limited and represented as price sensitive loads. The HydroCen dataset only represents price sensitive industry loads in Norway and Sweden. In total, the dataset includes 12.75 GW of price sensitive loads distributed as shown in table 4.6.

Area	Price sensitive load [MW]	Price range [€/MWh]
Finnmark	3	31.4
Helgeland	800	38.8 - 125
Norgemidt	980	30 - 125
Ostland	1870	27.8 - 187.5
Sorland	760	31.4 - 125
Sorost	490	30 - 125
Troms	270	31.4 - 125
Vestmidt	960	31.4 - 125
Vestsyd	1370	31.4 - 125
Sver-midt	4380	27.4 - 41.6
Sver-NN2	580	33.8 - 44.4
Sver-syd	290	27.4 - 46.6

Table 4.6: Distribution of price sensitive loads and price ranges

4.3.3 Rationing and flooding

If the demand is not covered, cost for not delivering electricity is known as the rationing price. In the HydroCen dataset this is set to 3000 €/MW with infinite capacity. To allow for spillage when reservoirs are flooded, the dataset also includes a spilling cost close to zero with infinite spillage capacity.

4.4 Exchange

The transmission capacities between countries in the HydroCen datasets are based on Statnetts grid description for 2030 (32). Internal transmission capacities between areas within each country are determined by plans for grid development published by Statnett or entso-e. The capacities have in some degree been adjusted to compensate for bottlenecks in the solution(28). Furthermore, losses in the transmission are included as a loss factor representing the fractional losses of the exchanged energy. The loss factor is set between 0 and 5 % on all transmission lines.
Compared to the reference scenario, the transmission capacity to Germany has been doubled. The total exchange capacity to continental Europe is represented in the dataset is described in table 4.7

Connection	Capacity [MW]
Vestsyd - GB-midt	1400
Vestmidt - GB-North	1400
Sorland - Nederland	700
Sorland - Tysk-nord	2800
Sorland - Danm-vest	1600
Total:	7900

Table 4.7: Exchange capacity over HVDC cables (29)

Chapter 5: Description of cases and sensitivity analysis

To analyze the impact of multi market modeling on a future scenario of the power system, three case are run. First the model is run with no reserves, then the reserves are allocated within the entire Nordic area and lastly the reserves are allocated within each price area in the Nordic region. The cases are run with sensitivity regarding the volumes reserved. A detailed description of the cases and sensitivity analysis is described in this chapter. As it is expected that more effect will be held back in balancing markets, Case II and III has been run with total reserve procurement of 300, 600, 900, 1200 and 1500 MW for both up and down regulation. To test the cases under different climatic conditions, all cases are run on week 9 and 31 in 1988, to consider both a winter and a summer week in a normal inflow year. Before presenting the cases in more detail, this chapter will present common background and methodology for all the cases.

Common factors	Value
Simulation year	1988
Simulated weeks	9 and 31
Dataset	HydroCen low emission
Strategic part	FanSi

Table 5.1: Common factors for all cases

Reserve units

To be allowed to supply reserves in the current reserve markets, the generating unit must be of a certain dimension. In aFRR bids submitted are required to be minimum 5 MW and maximum 35 MW while in mFRR the bids must be larger than 10 MW (26). Moreover, the plants needs to be able to deliver the reserves within 30 seconds in aFRR. As hydro power has both the ability to respond quickly and the required power output, they are well adapted to provide reserve procurement. In reality, a few, big power plants are supplying reserves to the power system, however the supplying modules are confidential. The author has therefore picked out 30 hydro power modules with both high generation capacity and reservoir size to deliver reserve procurement. The modules are evenly distributed throughout the price areas. The modules for reserve procurement is listed in the table 5.2 bellow. When it comes to the thermal unit, the same requirements hold. Therefore, also a selection of thermal units are chosen to supply reserves. In Norway, no thermal units are defined to supply reserves. In Finland, Sweden and Denmark the contribution from thermal units is more significant. Both the thermal units and the hydro power modules defined to supply reserve procurement are added in subsets in the model. Resultingly, the following sets are implemented in the model.

Sets for reserve procurement:

$\mathscr{A}^N$	Set of areas a in the Nordic power system
$\mathscr{R}_a^{res}$	Set of reservoirs for reserve procurement in area a
$\mathscr{P}_a^{res}$	Set of thermal units for reserve procurement in area a

Area	Reserve modules	Area	Reserve modules
Ostland	Ovre Vinstra	Sorland	Holen 3
	Nedre Vinstra		Brokke
	Osa		Duge
Vestsyd	Oksla	Vestmidt	Matre H
	Roldal		Steinsland
	Sauda 2		Jostedal
Norgemidt	K4 Tafjord	Hallingdal	Borgund
	Driva		Torpa
	Bratsberg		Nore 1
Troms	Siso	Helgeland	Rana
	Skjolmen		Ovre Råssjga
	Kobbelv		Storglomv
Finnmark	Alta	Sver-midt	Krv Trangsle
Telemark	Sundsbarm	Sver-on1	Krv Ritsem
	Vinje		Vietas-suorv
Sver-on2	Umulspen	Sver-NN1	Stalon
	Krv Gideogmo		Krangede
Sver-NN2	Sallsjø	Sver-syd	Hoeljes

Table 5.2: Modules for reserve procurement chosen by the author

Individual unit supply of reserves

For a generating unit to supply reserves, sufficient capacity must be available for up and down regulation. Consequently, constraint 5.1 - 5.4 are added to avoid the exceeding of capacity. The dual value of equation 5.1 and 5.2 represent the marginal price for upward reserve procurement for each individual the reservoir or thermal unit. If the constraint is nonbinding, the dual value is zero, and hence the reserves can be supplied freely. However if the constraint is binding, there are two cases. Either the unit produces at maximum capacity, making it impossible to supply reserves. Or the provided reserve equals the difference between production and maximal capacity. In the first case the dual value gets high and does not reflect the reserve cost since the supplied reserve is zero. In the other case we achieve a cost for the reserve procurement. The same analogy can be used on the downward reserve constraints in equation 5.3 and 5.4. For downward regulation, the model must insure that the system has enough available effect to turn of. Therefore restriction 5.3 and 5.4 are added to make sure that enough dispatchable generation is turned on. The equation states that production must be larger than the reserved amount from each unit. Lastly, equation 5.5-5.8 limits the maximum supply of capacity from each generating unit. The limit is based on the maximum allowed bid in the RKOM market.

$$w_{ark}^{H} + z_{ark}^{H\ up} \leq W_{ark}^{H_{max}} \tag{5.1}$$
$$w_{apk}^{T} + z_{apk}^{T\ up} \leq W_{apk}^{T_{max}} on_{apk} \tag{5.2}$$
$$z_{ark}^{H\ down} \leq w_{ark}^{H} \tag{5.3}$$
$$W_{apk}^{T_{min}} on_{apk} + z_{apk}^{T\ down} \leq w_{apk}^{T} \tag{5.4}$$
$$\forall a, r, p, k \in \mathscr{A}^{\mathscr{N}}, \mathscr{R}_a^{res}, \mathscr{P}_a^{res}, \mathscr{K}$$

$$z_{ark}^{H\ up} \leq 35 \tag{5.5}$$
$$z_{ark}^{H\ down} \leq 35 \tag{5.6}$$
$$z_{apk}^{T\ up} \leq 35 \tag{5.7}$$
$$z_{apk}^{T\ down} \leq 35 \tag{5.8}$$
$$\forall a, r, p, k \in \mathscr{A}^{\mathscr{N}}, \mathscr{R}_a^{res}, \mathscr{P}_a^{res}, \mathscr{K}$$

where:

w_{ark}^{H}, w_{apk}^{T}	Production from unit r/p $[MW]$
z_{ark}^{H}, z_{apk}^{T}	reserve procurement from unit unit r/p for up/down regulation $[MW]$
$W_{ark}^{H_{max}}, W_{apk}^{T_{max}}$	Maximal capacity in unit r/p $[MW]$
$W_{apk}^{T_{min}}$	Minimum production in thermal unit p $[MW]$
on_{apk}	Binary variable describing if thermal unit p is off or on $[0/1]$

Reserve volumes

To decide the amount of volumes reserved in balancing markets, it is first taken into account the requirement of today and then adjusted with future scenarios. This case study focuses on the reserve procurement i aFRR and mFRR and has for simplicity combined the two to analyze the overall effect of reserve procurement. Today it is required that 300 MW are available in the Nordic power system for aFRR. In the capacity market for mFRR, RKOM, most capacity for up regulation is reserved for the winter season. In 2018/2019 a total volume of 647 MW was reserved during the winter season(23). As mFRR is less restricted in its participants, it is to be assumed that some of the capacity reserved in RKOM originates from consumers as industry loads and other dispatchable power procurers than the modules previously defined. As this version of PriMod only considers reservation from larger hydro power stations and thermal units, the reserved volume for mFRR is adjusted down to compensate for the underestimation of suppliers.

In 2021, with the implementation of the New Nordic balancing concept, the Nordic TSOs aims to increase the reserve procurement in aFRR to 600 MW for all hours of the day. In addition, a European standardization of the terms for FRR and new market solutions allows for more exogenous reserve exchange. Today, 100 MW is being reserved on the Skagerak 4 to supply Vest

Denmark with aFRR (33). If such exchange is found to be beneficial on all HVDC cables, one estimate could be a 10 % reservation on all HVDC cables from Norway. This would represent an increased reservation of 660 MW from the Nordic region as described by table 5.3. If the HVDC cables from Sweden also would supply, this requirement would increase further.

Connection	Name	Export capacity	10%	Type	In operation
Norway-Sweden	Several lines	3695 MW	-	AC	Yes
Norway-Denmark	Skagerak 1-4	1700 MW	170MW	HVDC	Yes
Norway-Netherlands	NorNed	700 MW	70MW	HVDC	Yes
Norway-Germany	NordLink	2800 MW	280MW	HVDC	exp 2020
Norway-Great Britain	North Sea Link	1400MW	140MW	HVDC	exp 2021
Total		10295 MW	660 MW		

Table 5.3: Norwegian exchange capacities abroad (28; 29)

On a basis of the current reserve requirements, the increasing need for flexibility and the possibility for a platform of trading balancing resources in Europe, PriMod is tested with reserve requirements of 300, 600, 900, 1200 and 1500 MW for the Nordic area.

5.1 Case I: Base case

In case I, PriMod is run with the HydroCen dataset, without any contributions by the author. This is done to observe how the model responds to a scenario with no reserve procurement. The case serves as the base case and is a basis for comparison for the other cases. The base case utilizes the methodology as described in chapter 3.

5.2 Case II: Aggregated reserve procurement

The Nordic synchronous area is today only balanced within its outer limits. Resultingly, the balancing markets does not consider bottlenecks in the power system. Bottlenecks are considered by the TSO whom activates bids on the right side of the bottleneck if necessary. When the balancing is organized in this manner, a disturbance in one location can be balanced by an unit on the other side of the power system. To analyze the effect this structuring has on the power system when larger volumes are reserved in balancing markets, PriMod is run with an aggregated demand of 300, 600, 900, 1200 and 1500 MW reserve procurement. The model is run with these requirements for both up and down regulation simultaneously. The implemented methodology added by the author to achieve this is described in the next paragraph.

5.2.1 Methodology

To insure sufficient reserve capacity for the entire Nordic power system, the capacity balance equation 5.9 is implemented. The equation is added for both upward and downward regulation. Moreover, the equation states that the sum of reserves procured form all hydro power and thermal in the Nordics is equal to the Nordic requirement. This case does not consider exchange of reserves with exogenous areas and therefore no reserve transfer is included.

$$\sum_{a\in\mathscr{A}^{\mathscr{N}}} \big(\sum_{r\in\mathscr{R}_a^{res}} z_{ark}^H + \sum_{p\in\mathscr{P}_a^{res}} z_{apk}^T \big) = Z_a^{Req} \qquad \forall K \in \mathscr{K} \tag{5.9}$$

where:

z_{ark}^H	Reserve procurement from reservoir r in time step k $[MW]$
z_{apk}^T	reserve procurement from thermal unit p in time step k $[MW]$
Z^{Req}	Total required reserve procurement for the entire Nordic system a $[MW]$

5.3 Case III: Zonal reserve procurement

With the new Nordic balancing concept, it is suggested that each price zone should balance itself with FRR(24). The concept allows for cross zonal exchange of reserve products while taking into account restricting bottlenecks in the system. To study the effect this structuring of reserves has on the power system, PriMod is been run with distributed reserve procurement per model area. The allocation of reserves is based on numbers from Statnett, which distributes the reserves as described by table 5.4. As the model considers more price areas than the actual Nordic price zones, the reserve requirement has been distributed evenly within the areas within the price zones as described by table 5.4 and 5.5. In the simulations, PriMod is run with the zonal reserve requirement multiplied with 2,3,4 and 5 to achieve a total reserve procurement of 300, 600, 900, 1200 and 1500 as in case II. The model is run with these requirements for both up- and down regulation simultaneously.

Price zone	Reserve requirement $[MW]$	Representing model areas
NO1	24	Ostland, Sorost
NO2	33	Telemark, Sorland,Vestsyd
NO3	12	Norgemidt
NO4	21	Helgeland, Troms, Finnmark
NO5	24	Vestmidt, Hallingdal
SE1	33	Sver-ON1, Sver-ON2
SE2	24	Sver-NN1, Sver-NN2
SE3	54	Sver-midt
SE4	30	Sver-syd
DK2	20	Danm-ost
FI	25	Finland
Total	300	

Table 5.4: Distribution of reserve requirement per Nordic price zone

Model area	Reserve requirement $[MW]$
Ostland	24
Sorland	11
Sorost	0
Telemark	11
Vestsyd	11
Vestmidt	12
Hallingdal	12
Norgemidt	12
Helgeland	7
Troms	7
Finnmark	7
Sver-nn1	12
Sver-nn2	12
Sver-on1	16
Sver-on2	17
Sver-midt	54
Sver-Syd	30
Finland	25
Danm-ost	20
Total:	300

Table 5.5: Distribution of reserve procurement per model area

5.3.1 Methodology

To implement the new Nordic balancing concept, a reserve balance for both upward and downward reserve procurement is implemented for each area. Equation 5.10 represents this reserve balance and is implemented for both up and down regulation. The equation states that the sum of reserves supplied from hydro power and thermal unit within each area plus the net exchanged reserves should equal the required reserve capacity in the area. In addition, equation 5.12 limits the exchanged reserve capacity to not exceed 10 % of the transmission capacity. If a neighboring area is supplying upward regulation, the transmission line has to hold back the reserved effect from the transmission. Likewise, if the area is supplying downward regulation, the transmission must be larger or equal to the supplied downward reserve quantity as described by equation 5.11 and 5.13.

Reserve area balance

$$\sum_{r \in \mathscr{R}_a^{res}} z_{ark}^H + \sum_{p \in \mathscr{P}_a^{res}} z_{apk}^T + \sum_{b \in \mathscr{A}^N} (z_{bak}^E - z_{abk}^E) = Z_a^{Req} \qquad \forall a, K \in \mathscr{A}^{\mathscr{N}}, \mathscr{K} \tag{5.10}$$

where:

z^{H}_{ark}	Reserve procurement from reservoir r in time step k $[MW]$
z^{T}_{apk}	Reserve procurement from thermal unit p in time step k $[MW]$
z^{E}_{abk}	Transferred reserve procured from area a to area b in time step k $[MW]$
Z^{Req}_{a}	Required reserve procurement for up regulation in area a $[MW]$

Reserve transmission constraints

$$-T^{max}_{ab} \leq tr_{abk} + z^{E^{up}}_{abk} \leq T^{max}_{ab} \tag{5.11}$$

$$z^{E}_{abk}{}^{up/down} \leq 0.1 * T^{max}_{ab} \tag{5.12}$$

$$z^{E^{down}}_{abk} \geq tr_{abk} \tag{5.13}$$

$$\forall a, b, k \in \mathscr{A}^{\mathscr{N}}, \mathscr{A}^{\mathscr{N}}, \mathscr{K}$$

where:

T^{max}_{ab}	Maximum transmission capacity from area a to area b $[MW]$
tr_{abk}	Transferred capacity from area a to b in time step k
$z^{E^{up/down}}_{abk}$	Transferred up/down regulation capacity from area a to b in time step k $[MW]$

Chapter 6: Results

This chapter will present the results from the cases described in chapter 5. As the model in use is a prototype, case I will present the the model response without adjustments by the author. Cases II and III will investigate how the reserve prices for up and down regulation changes with increased shares of effect reserved for balancing markets. Furthermore, the results will highlight how the economic surpluses distributes in the different cases and how the market equilibrium changes in both energy and reserve market for different shares of reserve procurement.

6.1 Case I: Base case

The results represented in this case represents how the model responds with no reserve procurement. Many of the results from this case serve as a basis for comparison. In addition, some of the results are valid for all the cases as they are not affected by the increased reserve procurement e.g inflow and power production from wind and PV. The base case illustrates the natural response of PriMod with no adjustments implemented by the author.

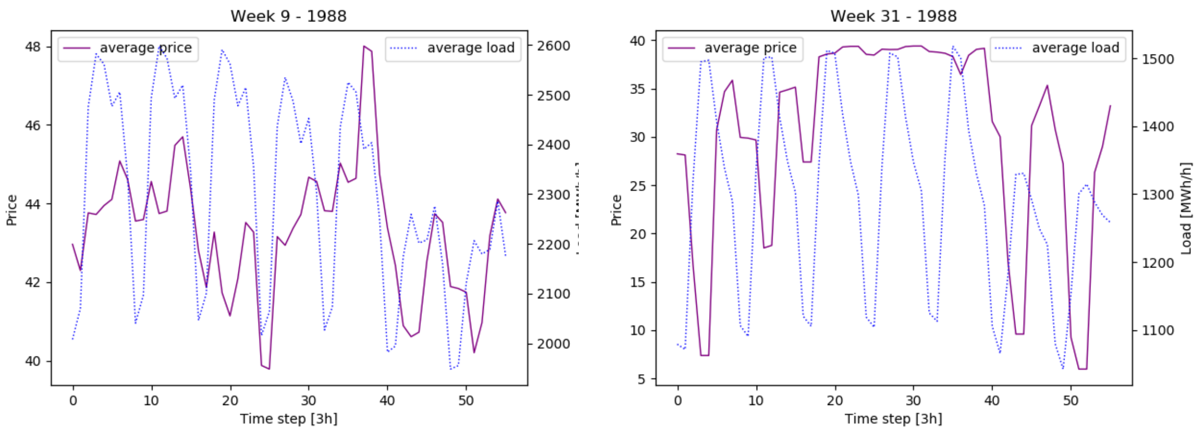


Figure 6.1: Case I: Average price and load

6.1.1 Price and load

Figure 6.1 shows the average price and load for the Nordic price areas for week 9 and 31. From the graph it can be observed that the price follows the same pattern of the load e.g when the load is high during the morning and afternoon, the prices also peak. However in week 9, it can also be seen that even though the peak load is highest during the morning, the prices are highest during the peak in the afternoon. In week 9 the prices are quite high, varying between 40 and

48 € /MWh. The average area price in week 31 is lower than the price in week 9, ranging from under 10 to 40€ /MWh. In addition the load is also much lower in week 31 than in week 9.

Production mix

In figure 6.2 and 6.3 the production from thermal, hydro and wind/PV power is presented for week 9 and week 31. The thin black line shows the average marginal price. From the figure it can be seen that both thermal and hydro production follows the same pattern as the price and hence the load. As wind ad PV is dispatchable generation, it has to produce when it can and does not follow the demand/load curve. From the green curve, representing the wind and PV, it can be seen that the lowest point production is also the time when the price is highest. In week 31, it can be seen that the time steps with peaking renewable production corresponds with the time steps with prices valleys. The figures also show that hydro power highly dominates the Nordic power system with a maximal production of over 35 000 MW, compared to 9100 MW maximal thermal production and max 14 000 MW from wind/PV.

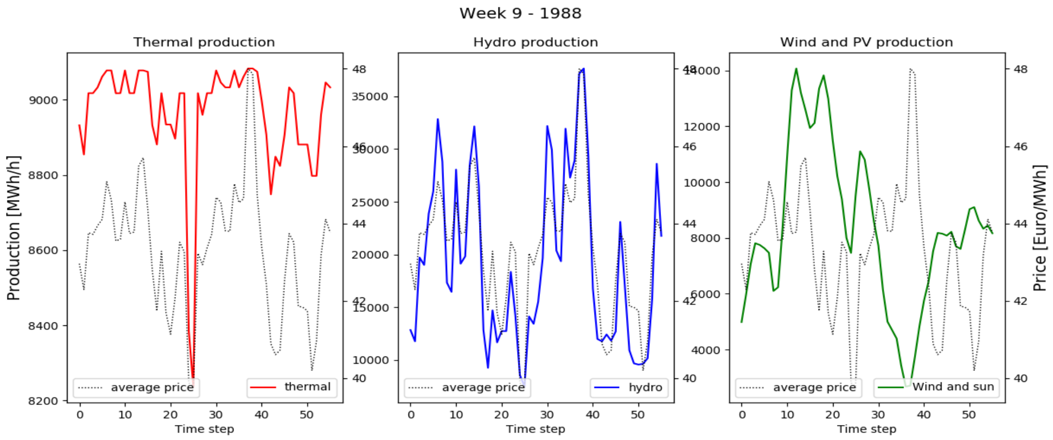


Figure 6.2: Case I: Total power production in the Nordic areas in week 9

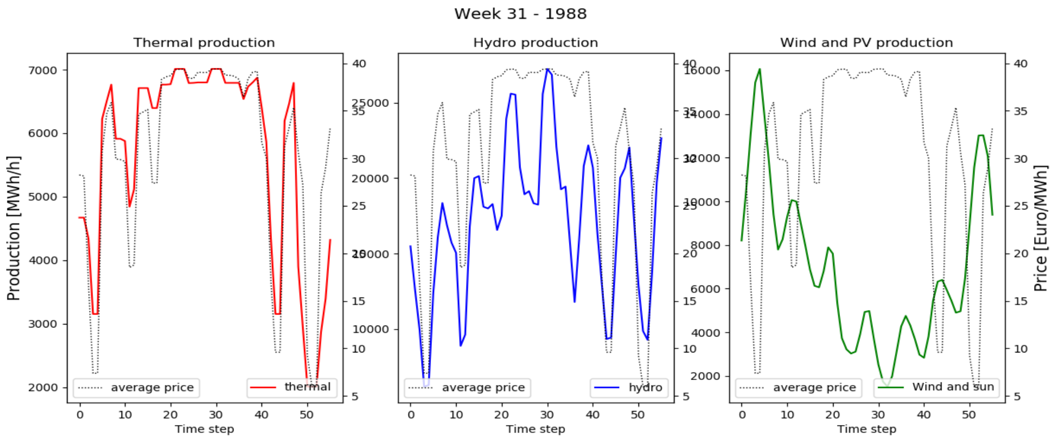


Figure 6.3: Case I: Total power production in the Nordic areas in week 31

6.1.2 Market cross

To illustrate how the energy market is cleared at a given time step in each area, the market cross is plotted for Ostland, Hallingdal, Sver-midt and Danm-ost at time step 38 in week 9 and 4 in week 31. The different colors represent the different supply and demand types as explained in chapter 3.3 and table 3.2. The equilibrium, hence the area price is marked with a pink dotted line. From the market clearings it can be observed that except for some thermal units on in Ostland, the areas are mainly supplied with hydro power(blue steps) and import (orange line). In Hallingdal, apriximately 3000 MWh/h is being exported (yellow step) and 1500 imported in time step 38 of week 9. The surplus hydropower is therefore exported. In Sver-midt and Danm-ost thermal units cover the base load. The area price in Danm-ost is much higher than in the remaining areas as a result of a energy imported at a very high price. Neither areas have any renewable supply from wind or PV in time step 38.

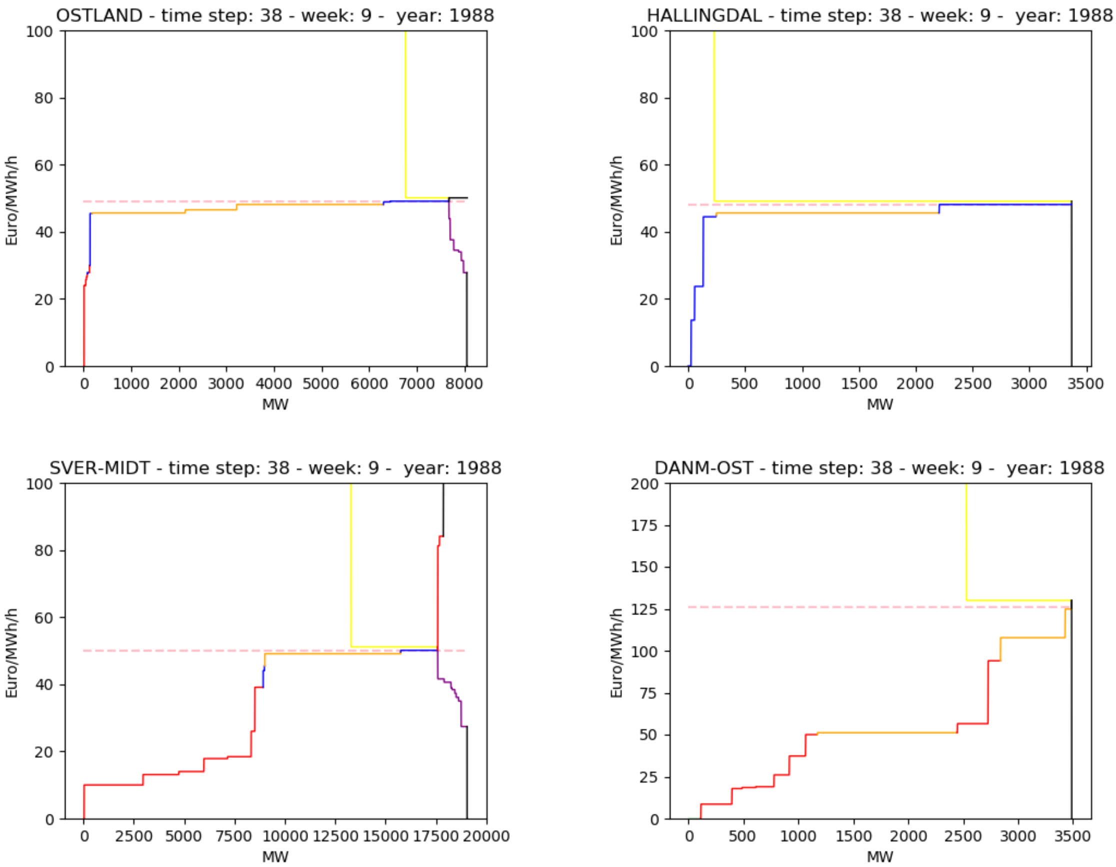


Figure 6.4: Case I: Market clearings in week 9 for time step 38

In figure 6.5, it can be observed that Ostland imports almost all its consumed power and exports none. In Hallingdal some hydro power produce, resulting in a larger share of export than import, meaning that the power goes through Hallingdal to supply its neighboring areas. Danm-ost has a much higher share covered by wind, whereas the remaining load is covered by thermal units and import simularily to Sver-midt. As a result of lower load and increased renewable production, the price in Danm-ost is much lower in week 31 than week 9.

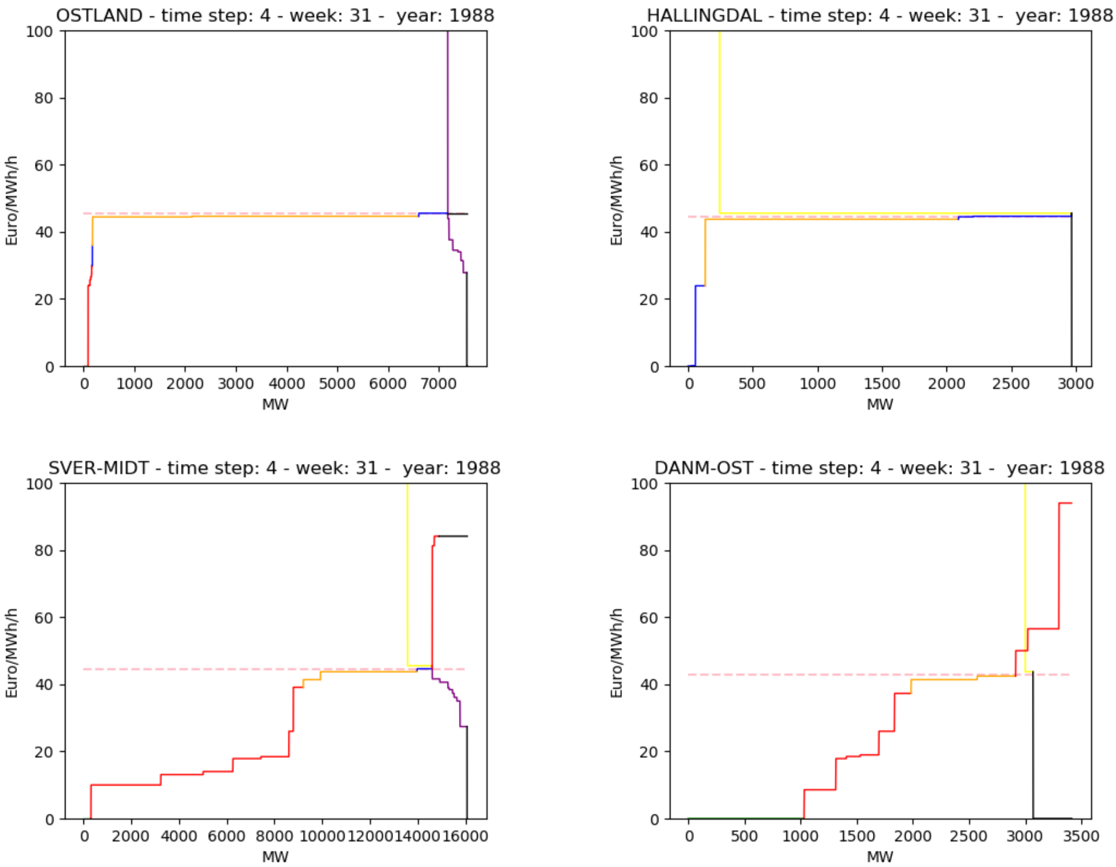


Figure 6.5: Case I: Market clearings in week 31 for time step 4

6.1.3 Economic surplus

The economic calculations in case I shows that the economic surplus is higher in the winter week than in the summer week. This is as expected since the load is much higher during winter, increasing both consumer and producer surplus. The congestion rent doubles, representing increased exchange of energy in week 9 compared to week 31.

Week	Surplus [Million €]			
Nr.	Producer	Consumer	Congestion rent	Total
9	1112,99	16996,26	86,45	18195,71
31	14098,73	733,40	44,86	14876,99

Table 6.1: Case I: Total surplus

6.2 Case II: Aggregated reserve procurement

The following section contains results regarding case II with reserves procured within the Nordic synchronous area. The case is run as described in chapter 5.2.

6.2.1 Prices

The average area and reserve prices are plotted for simulations with 300, 600, 900, 1200 and 1500 MW reserve procurement. Figure 6.6 and 6.7 shows the average area price in the Nordic power system for week 9 and 31. The figure illustrates that the average power price is equal in all scenarios for almost all time steps. The exception is at the extremities, when the price is very high or low. This is illustrated in the zoomed graph on the right hand side of the figures. The price peaks can be observed at time step 14 and 38 in week 9. In those time steps the area price is increasing with increasing amounts of reserve procurement. As a result of different reservoir handling, the price in the case with 600 MW reserved is lower than in the case with only 300 MW during the peak as illustrated by the pink an red line, this will be further discussed in chapter 7.1. In week 31 the deviations are less noticeable, but follows the same trend as week 9. In the low peaks, the average price decreases for increasing reserve procurement as illustrated by the zoomed graph in figure 6.7.

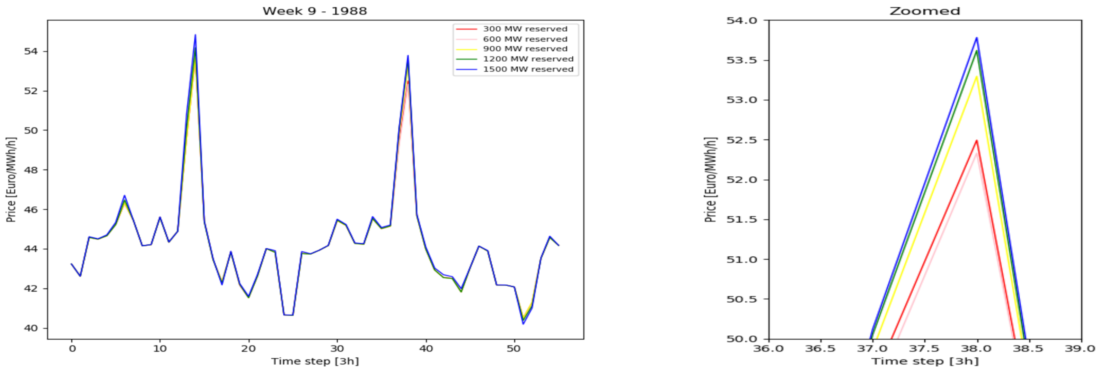


Figure 6.6: Case II: Average price in the Nordic areas in week 9

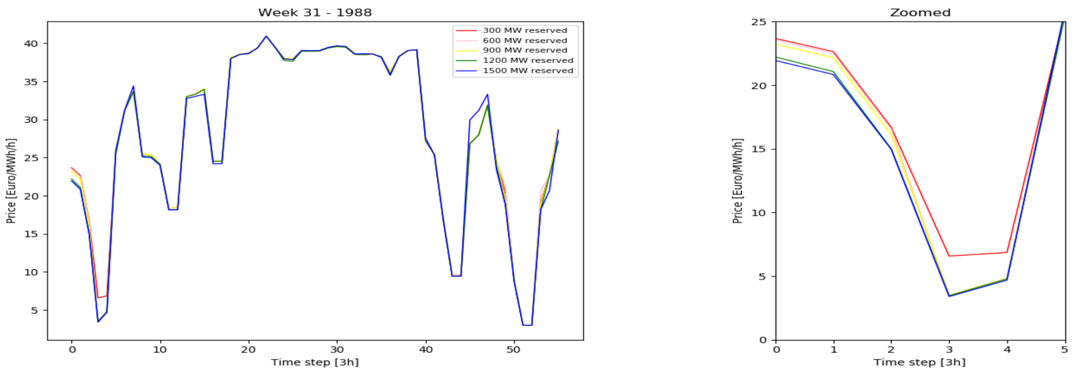


Figure 6.7: Case II: Average price in the Nordic areas in week 31

Figure 6.8 shows the prices for up regulation in week 9 and 31 respectively. In both weeks the up regulating price gets very high for the scenario with 1500 MW reserve procurement. The response for up regulation shows the higher prices during the winter week than during summer. It can also be observed that the up regulating prices reach its highest prices when the load is high. Furthermore, the duration curve illustrates that when less than 600 MW is reserved in week 9, up regulation can be supplied freely. The same goes for week 31, when less than 900 MW is being held back.

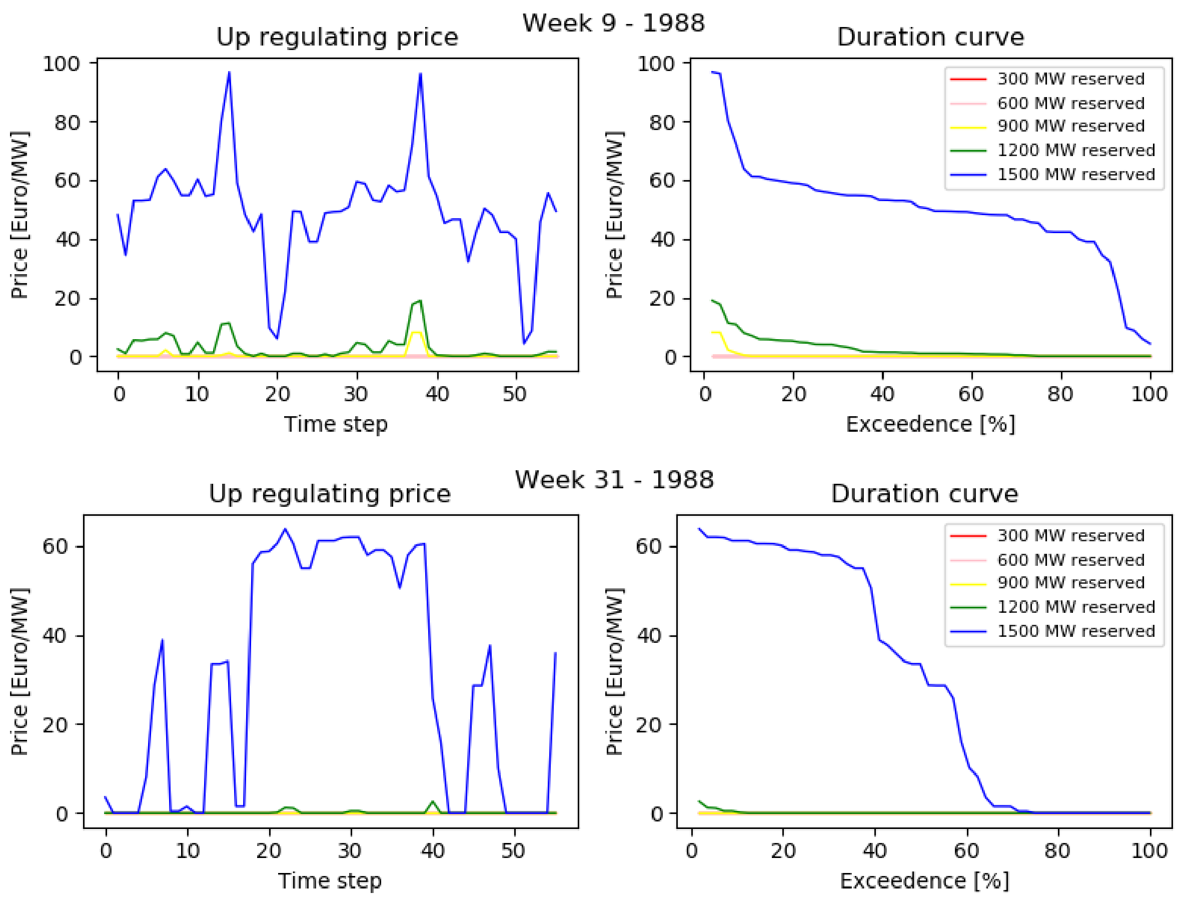


Figure 6.8: Case II: Up regulating prices

Similar to figure 6.8, figure 6.9 shows the price for down regulating and the associated duration curve. The down regulating prices gets very high during summer for increased amounts of reserves. It can be observed that the prices reaches its highest values at the time step were the load is at its lowest and/or the share of renewable production is high. In winter, down regulation is supplied freely when less than 900 MW is required. If 1200 MW is procured, it can be supplied freely 90 % of the week. In week 31, down regulation is supplied freely 70 % of the week if less than 900 MW is reserved. However, for the simulations with more than 600 MW procured, down regulation prices exceed 60 € /MWh in the peaks, even reaching 120 € / MW for the simulation with 1500 MW procured.

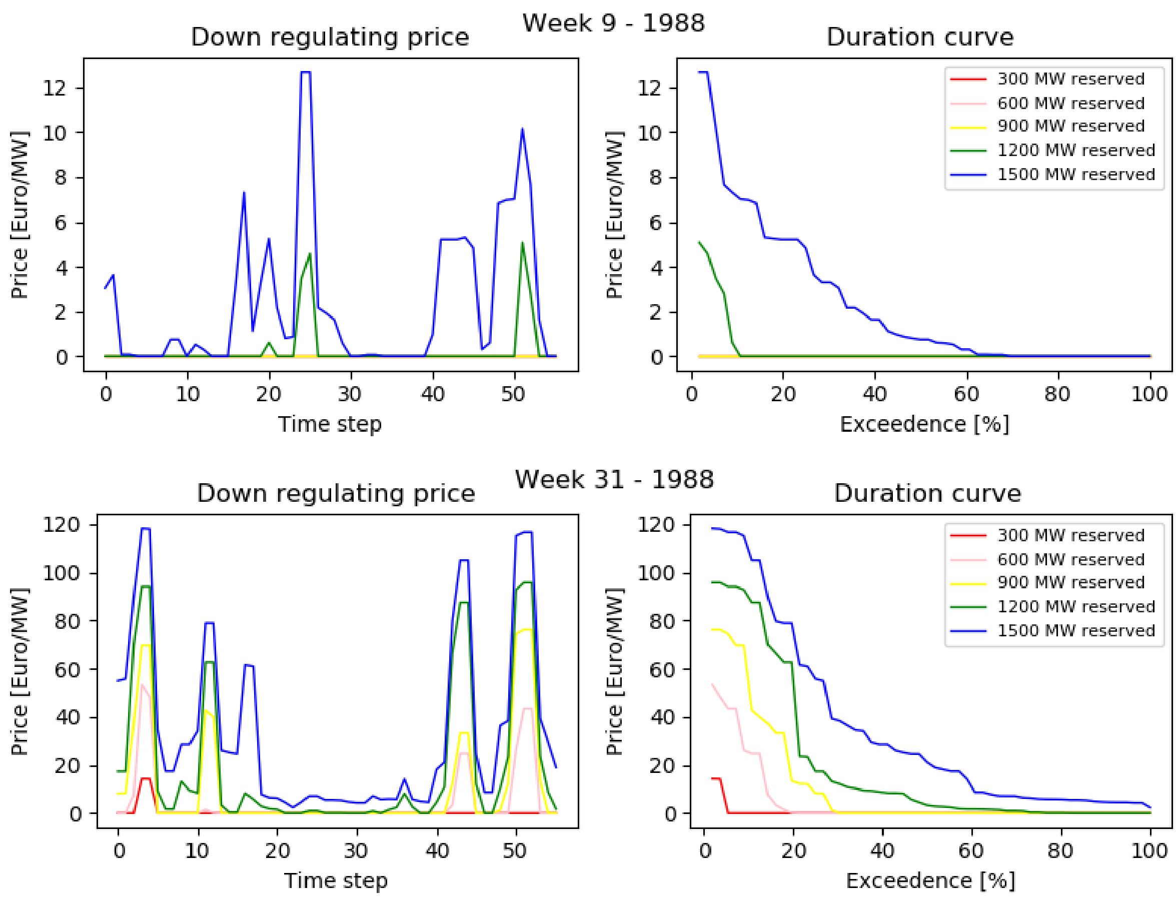


Figure 6.9: Case II: Down regulating price

When comparing the reserve prices and the average area price and load it can be observed that the up regulating price achieves high values when the price and load is high. This is a result of reducing the available effect in the system, pushing the prices up as described by chapter 2.3.2. For down regulation, the prices peak when the load is low and/or dominated by non dispatchable generation. In that case, dispatchable power units are forced to supply energy at area prices under its marginal costs.

Supplied reserve capacity per area

Figure 6.10 describes how the reserve procurement distributes for up regulation in the peak at time step 38 in week 9. The figure shows that the Norwegian areas will provide reserves first. As the procurement increases, most areas reserve more and more capacity. Most Norwegian areas will provide closer and closer to their maximum capacity. Norgemidt procures maximal already when 600 MW is procured. Danm-ost never has to provide up regulating capacity in this case. In addition, the Swedish areas procure less capacity than the Norwegian. Figure 6.11 shows how the down regulating reserves distributes at the reserve price peak in week 31 at time step 4. From the figure it can be seen that most of the Norwegian, hydro dominated areas wont supply reserves until 1200 MW are required. It is mostly the thermally dominated areas in Sweden, Denmark and Finland that covers the base requirement.

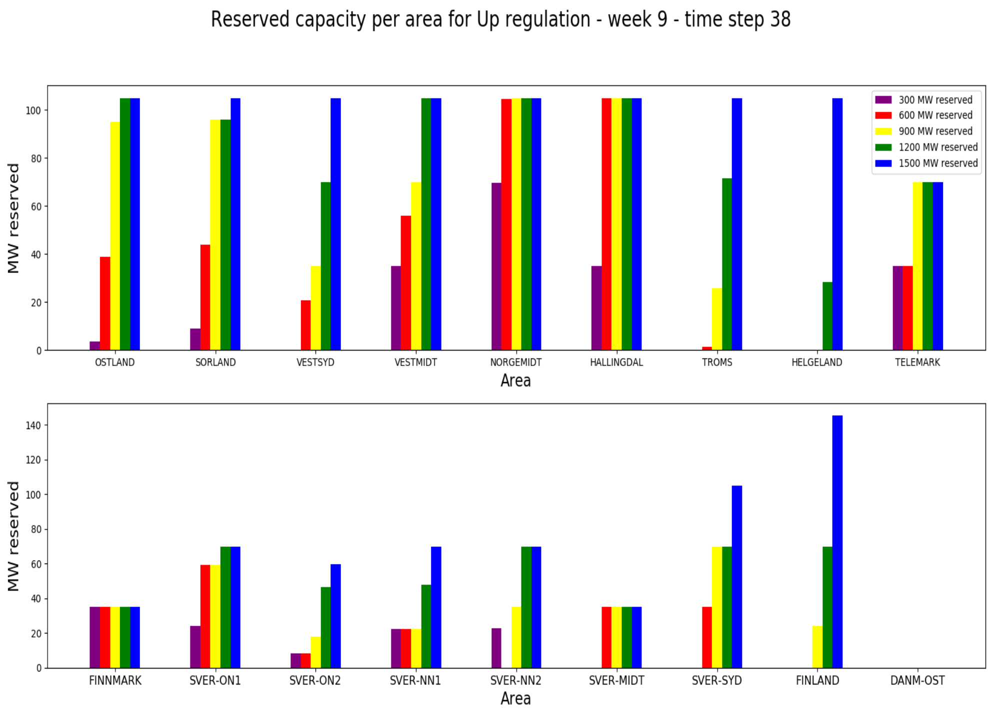


Figure 6.10: Case II: Reserved capacity for up regulation per area in week 9 time step 38

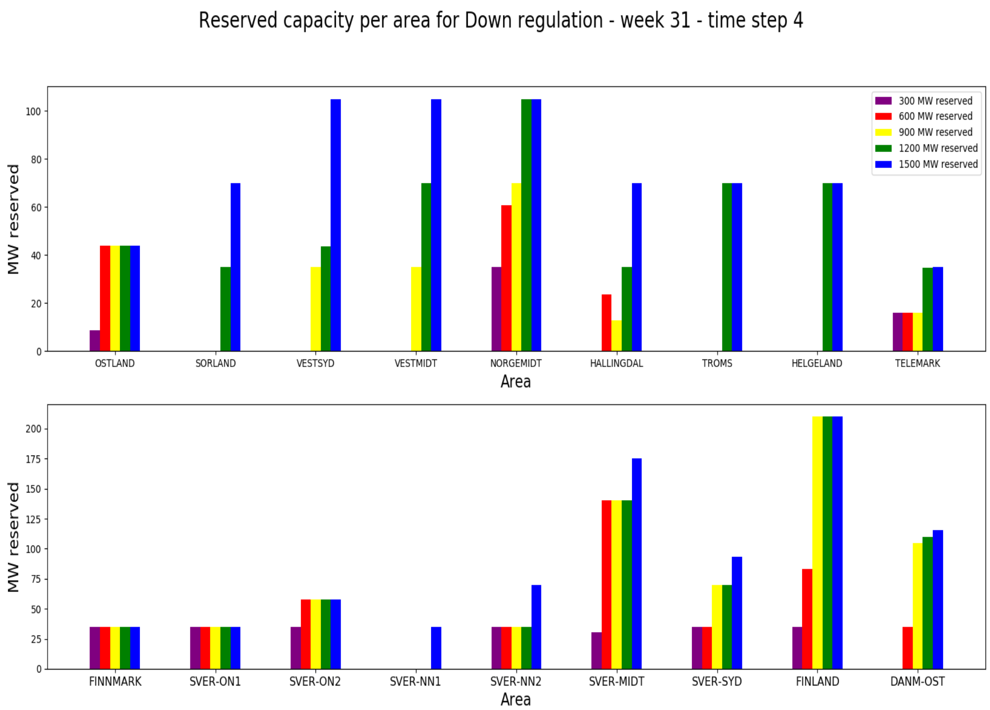


Figure 6.11: Case II: Reserved capacity for down regulation per area in week 31 time step 4

6.2.2 Market cross

Changing market cross for reserve procurement

The market cross for reserve procurement is plotted for the extremities when the reserve price is highest. For up regulation this is time step 38 in week 9 and for down regulation this is time step 4 in week 31. Figure 6.12 shows how the market cross for reserve procurement change for different reserve requirements. The different dotted lines represents simulations with different reserve requirements. The blue steps represent reserves supplied from hydro power and the red steps represent reserves supplied from thermal units. The grey lines represent the reserve requirements. The reserve price can be read at the equilibrium where the colored graph crosses the gray line with the same line style. From the graphs, it can be observed that up to 500 MW up regulation can be supplied freely in time step 38 in week 9. Similarly, close to 400 MW down regulation can be supplied freely in time step 4 of week 31. For up regulation the prices gets high when the thermal units steps in. In that case, almost all thermal units are producing at their maximal capacity or is shut of. As the model includes startupcosts on thermal units, it does not find it optimal to turn on more thermal units to relieve the remaining whom run at maximum capacity. To deliver reserves, this results in very high dual values of the reserve constraints limiting the thermal production.

In week 31, its the reservation cost of hydro power modules that defines the up regulating price. The thermal production is not as bound as the load is lower in the summer week and therefore covers the base down regulating requirement. In the summer, inflow and reservoir levels are lower, leading to higher water values. As some hydro power units are forced to produce when the water value is higher than the area price, the reservation price achieves very high values when the down regulating requirement increase.

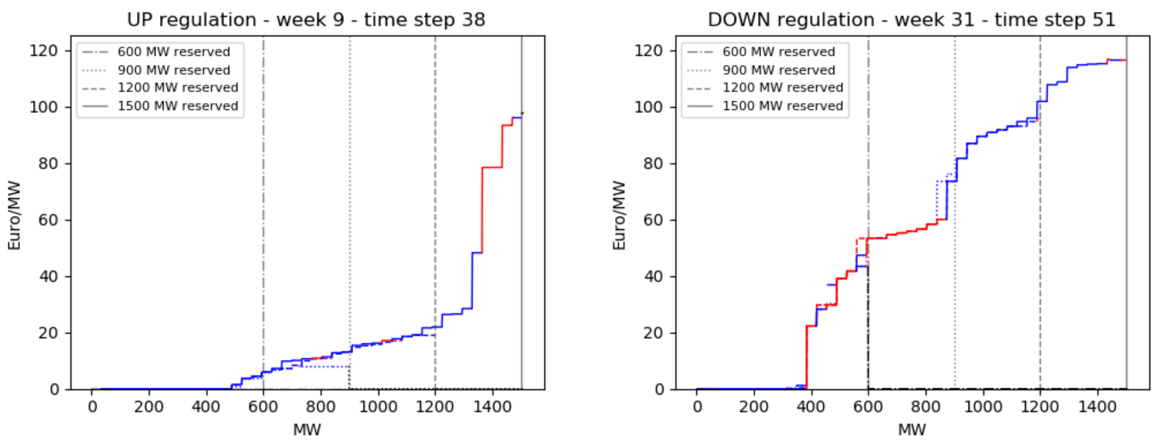


Figure 6.12: Case II: Changing market cross for reserves for increased procurement

Changing market cross in the energy market

Figure 6.14 shows how the market cross changes when 1500 MW is reserved in Ostland, Hallingdal, Sver-midt and Danm-ost compared to the case with no reserve procurement. The dotted line represents the supply when 1500 MW is reserved while the straight line represents the case with zero reserve procurement. The color describes the origin of the supply and demand as described by table 3.2. Furthermore, a zoomed graph is presented where the effect is difficult to observe.

In week 31, when down regulation is dominating, production is forced into the market, at a lower price than the producers marginal costs. Therefore the supply curve is shifted to the right, decreasing the area prices. This effect can be observed in the plot for Sver-midt for week 31 in figure 6.14. In the other areas the effect is very small.

In week 9, the up regulating prices are the most dominant, decreasing the available effect in the power system. Resultingly, the area price increase. This effect can be observed in all areas presented. However, it can also be observed in Hallingdal that 30 MW are supplied at a lower cost when 1500 MW are being supplied than in the case with no procurement. This occurs at the beginning of the supply curve in Hallingdal and is a result of reservoirs achieving negative water values as water is forced to be bypassed to supply up-regulation. Moreover, figure 6.14 illustrates how the water values change when 1500 MW is procured compared to the base case. For example in Hallingdal,the 2000 MW supplied at 47 €/MWh in the base case is supplied for almost 50 €/MW in the case with 1500 MW reserve procurement.

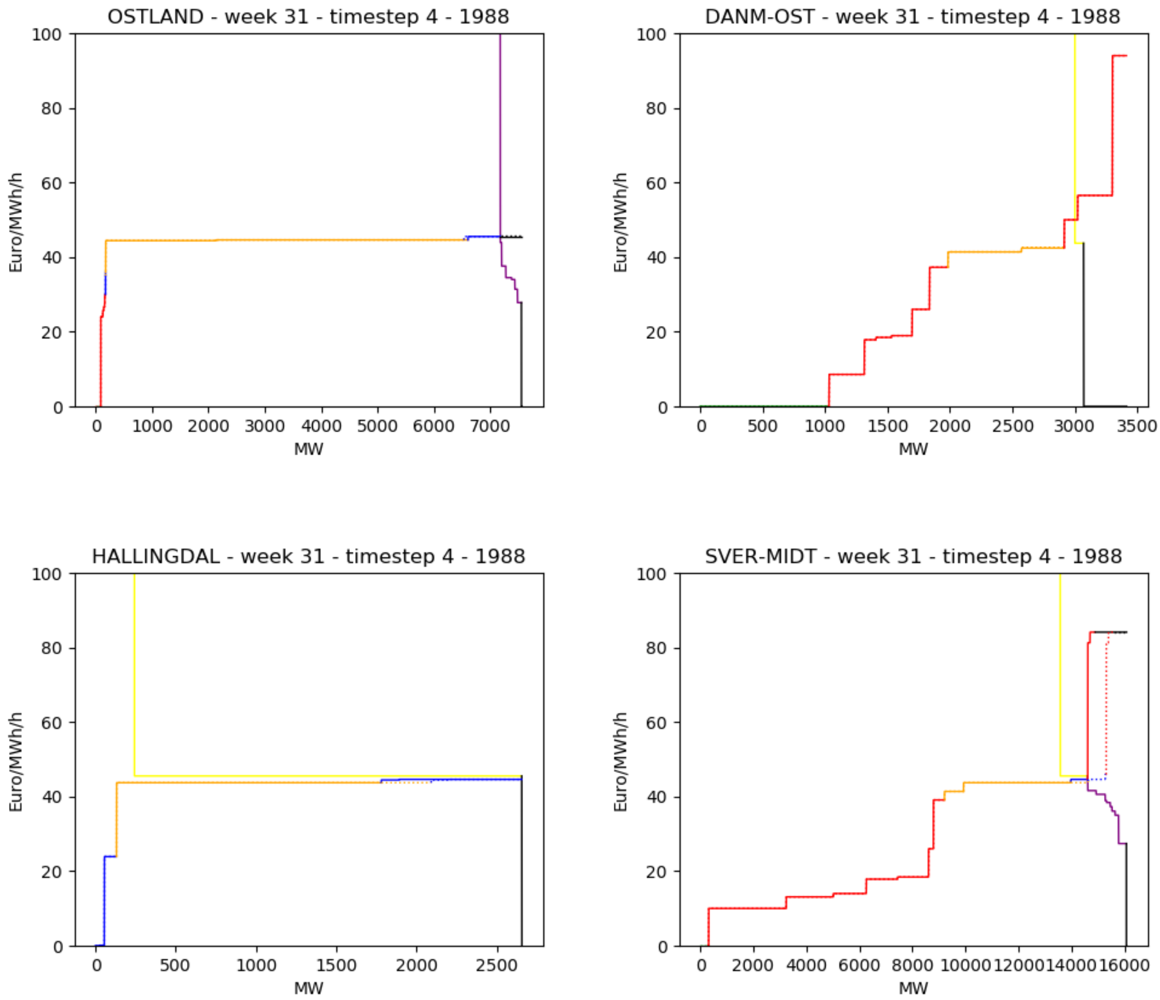


Figure 6.13: Case II: Changing market cross for energy in week 31

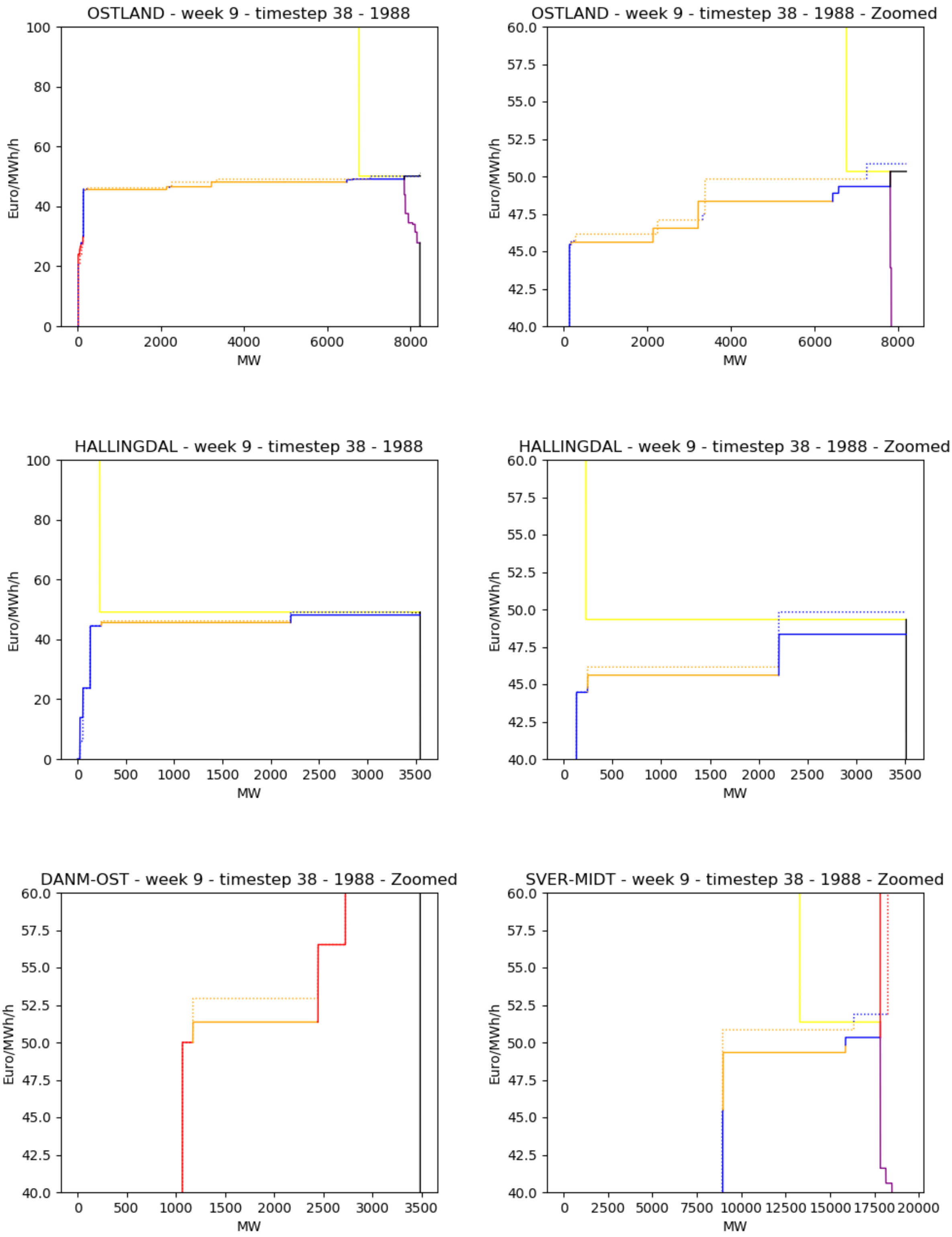


Figure 6.14: Case II: Changing market cross for energy in week 9

6.2.3 Economic surplus

Total surplus

An overview of the total surplus in the different simulation in case II is reported in table 6.2. The table shows that both consumer and producer surplus is higher during week 9 than week 31. From the table it can be observed that the producer surplus increase in week 9 and decrease in week 31 for increased reserve procurement. Contrarily, the consumer surplus decrease in week 9 whereas it increases in week 31 with higher capacity procurement. The only exception to this rule is in week 9 when the consumer surplus actually slightly increase when 600 MW is reserved. The congestion rent is quite stable in both weeks, but increases slightly for increased reservation. These results are expected as increased amounts of up regulation pushes the area prices up, increasing the producer surplus and decreasing the consumer surplus. Contrarily, for down regulation the area price decreases, increasing the consumer surplus and decreasing producer surplus for increased down regulation.

The results also show that the total surplus actually increase for increased volumes of procured reserve capacity. This is surprising, as it is expected that a stricter restriction will decrease the total surplus in the system. In week 9, it can be observed that the producer surplus increase more than the consumer surplus decrease and hence the total surplus increases. This effect will be further discussed in chapter 7.3.

Week	Reserved	Surplus [million €]			
nr.	effect [MW]	Producer	Consumer	Congestion	Total
9	300	1112,23	16995,52	86,45	18195,66
9	600	1112,22	16995,60	86,45	18195,74
9	900	1112,48	16995,30	86,45	18195,70
9	1200	1113,13	16995,02	86,50	18196,12
9	1500	1114,91	16993,54	86,59	18196,51
31	300	735,14	14089,30	45,08	14869,53
31	600	733,74	14090,30	45,36	14869,36
31	900	732,97	14090,85	45,43	14869,25
31	1200	730,82	14092,90	45,83	14869,55
31	1500	730,80	14093,27	45,42	14869,50

Table 6.2: Case II: Total surplus

Producer surplus

Table 6.3 demonstrates the technological origin of the producer surplus. The surplus from thermal units and Wind/PV increase in a very gradual manner in week 9 and decrease similarly in week 31. Furthermore, even though the load is higher in week 9, than week 31, the producer surplus from hydro power doubles in week 9.

Week nr.	Reserved effect [MW]	Producer surplus [million €] Hydro	Thermal	Wind/PV
9	300	2,03	546,92	564,74
9	600	2,08	546,88	564,74
9	900	2,17	547,02	564,76
9	1200	2,68	547,15	564,77
9	1500	3,37	547,76	565,24
31	300	5,76	371,54	358,89
31	600	5,72	371,28	357,79
31	900	5,55	370,95	357,53
31	1200	5,31	369,95	356,61
31	1500	5,41	369,95	356,49

Table 6.3: Case II: Distribution of producer surplus per technology

Reservation costs

Table 6.4 presents the cost of reserving capacity for all the tested scenarios in case II. The table shows that it is more expensive with reserve procurement at week 31 than week 9. When 1500 MW are being reserves both up regulation and down regulation is costly, whereas down regulation is almost free in the same scenario in week 9. Figure 6.26 and 6.27 shows what areas the reservation is distributed in. From the plot it can be concluded that the reservation costs mostly originates from the Norwegian areas. Danm-ost, which has a much higher load than many of the Norwegian areas, has the same reservation cost as many areas with much lower load, e.g Sorland when 1500 MW is reserved.

Week nr.	Reserved effect [MW]	Reservation costs [million €] Up reg.	Down reg.
9	300	0	0
9	600	0	0
9	900	0.05	0
9	1200	0,55	0,06
9	1500	12,47	0,60
31	300	0	0,026
31	600	0	0,50
31	900	0	1,64
31	1200	0,02	4,04
31	1500	7,50	8,83

Table 6.4: Case II: Reservation costs

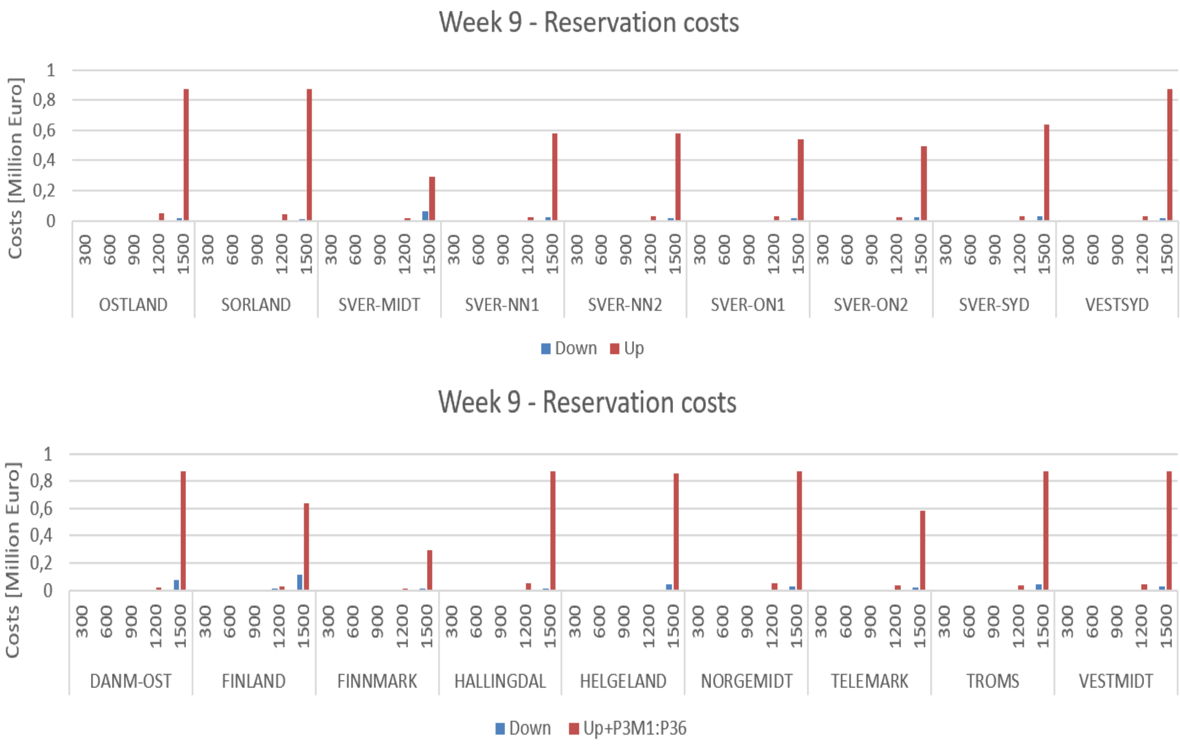


Figure 6.15: Case II: Distribution of reservation costs in week 9

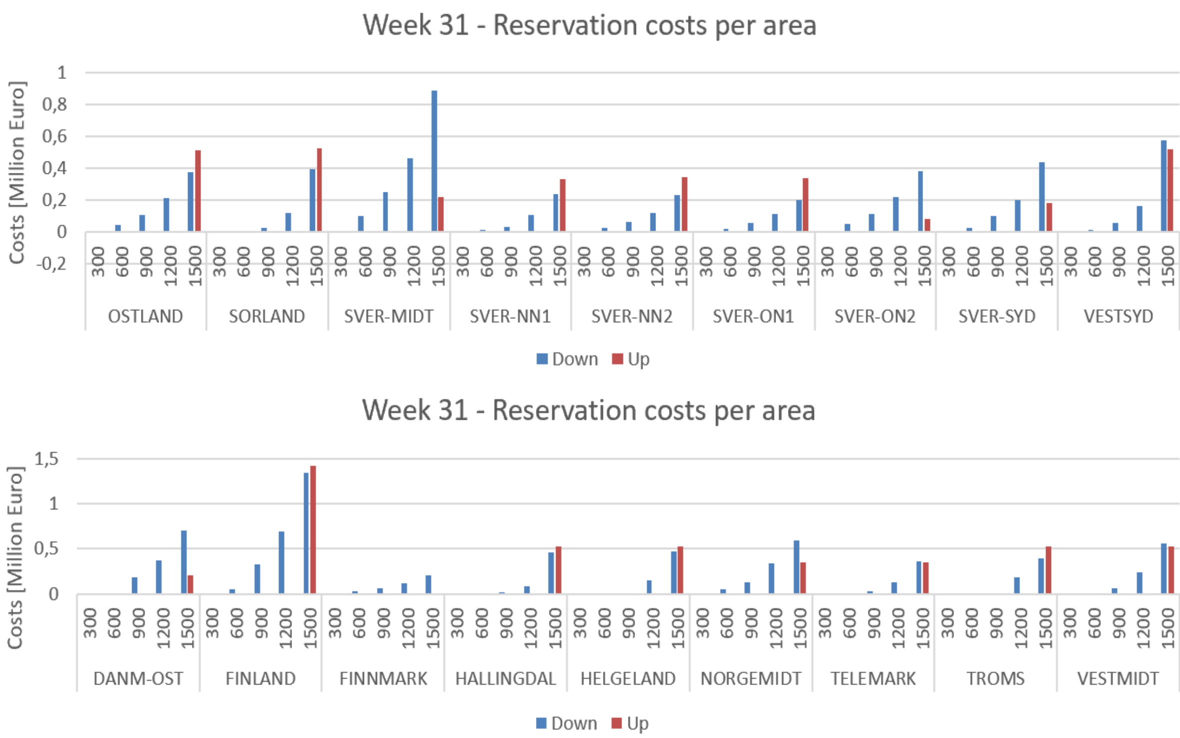


Figure 6.16: Case II: Distribution of reservation costs in week 31

6.3 Case III: Zonal reserve procurement

The following section contains results regarding case III with zonal reserve procurement. The case is run as described in chapter 5.3. First the simulated prices are presented, including the average area price and the average reserve prices for all the scenarios. When the reserves are procured within each price zone, each area will generate its own reserve price. To quantify how the reserve prices evolve, the reserve prices are represented with its average reserve price, weighted with the area load. Furthermore, the economic surplus and changing market crosses are presented.

6.3.1 Prices

In figure 6.17 and 6.18 , the average area price is plotted for week 9 and 31. The figure shows that the average area price in the different scenarios deviates in the high and low peaks during both weeks. The graph to the right in each figure is zoomed in on one of the extremities and show more clearly how the different scenarios deviates. In week 9, the average price increases or is equal for increased amounts of reserve procurement for all scenarios. The average price in week 31, illustrates the opposite trend where increasing reserve procurement decreases the average area price unless it stays equal.

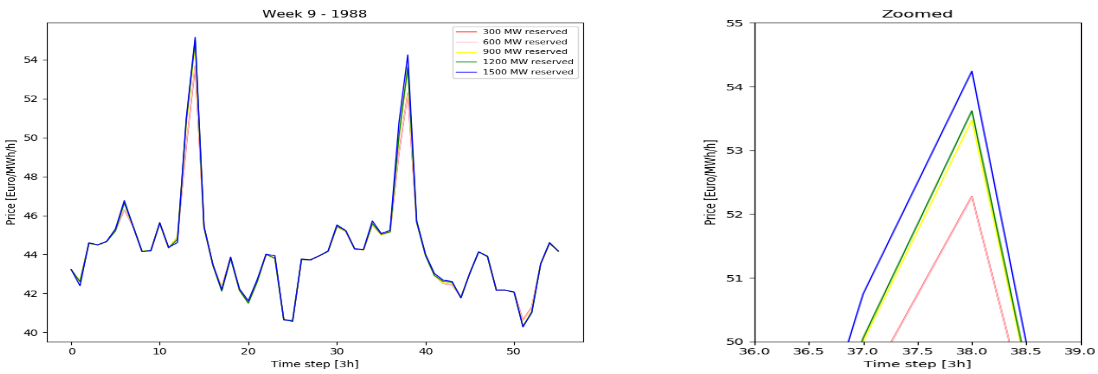


Figure 6.17: Case III: Average price in the Nordic areas in week 9

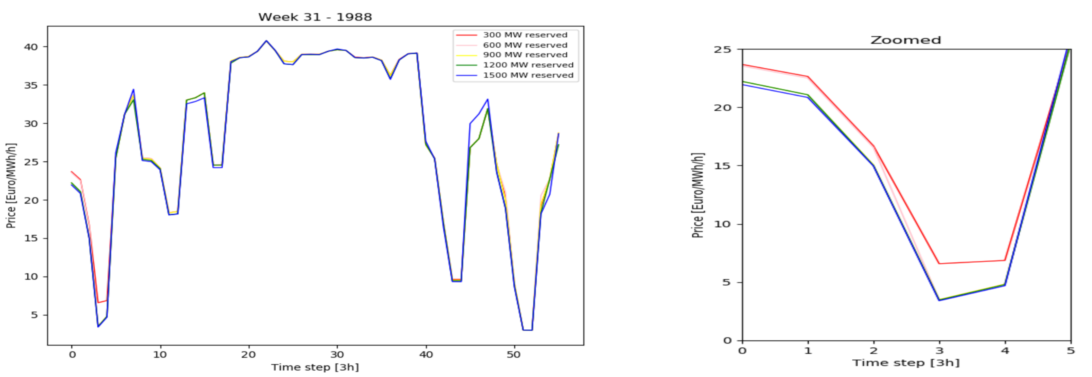


Figure 6.18: Case III: Average price in the Nordic areas in week 31

The average price for up regulation in case III increases for increased amounts of reserves procured as illustrated by figure 6.19. The price drastically increase when 1500 MW is procured. From the duration curve it can be observed that up to 900 MW can be supplied freely for 90 % of week 9. In week 31, reserves up to 1200 MW can be supplied for less than 5 €/MW for all hours.

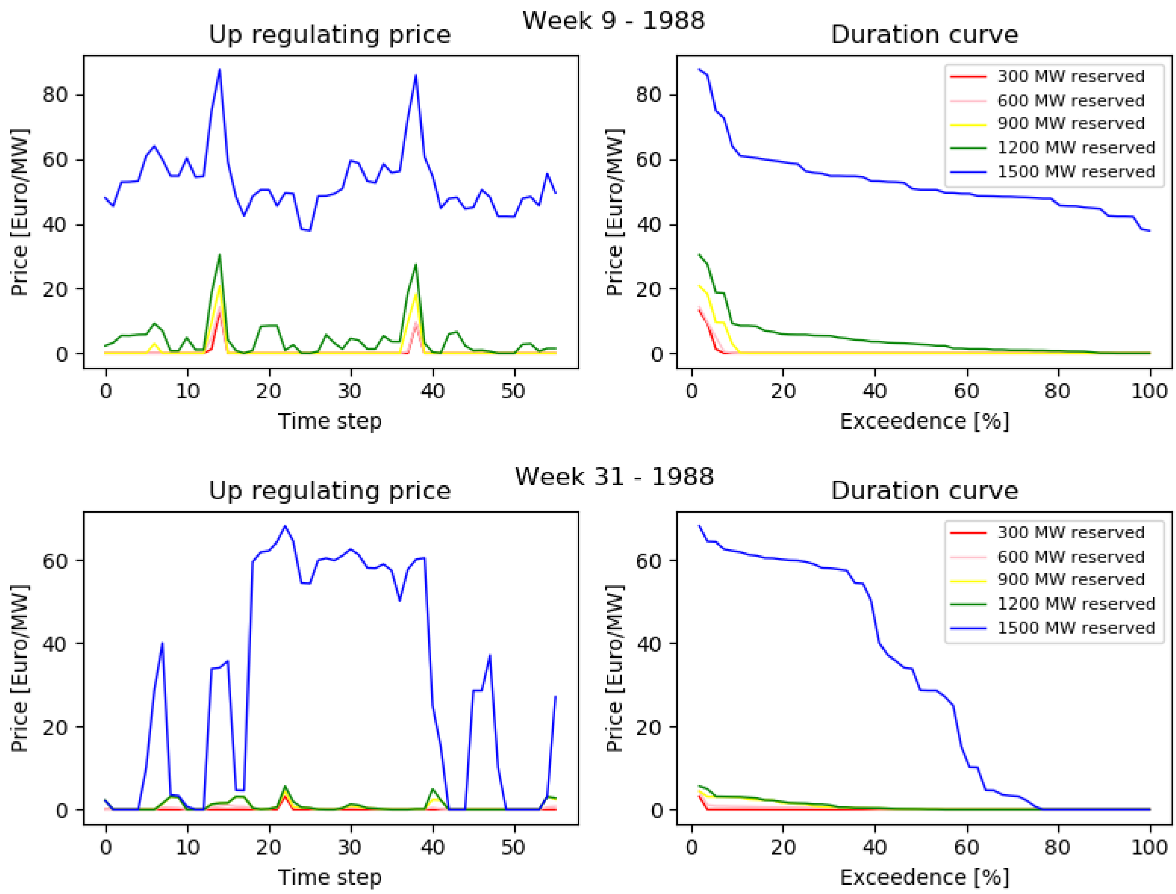


Figure 6.19: Case III: Average up regulating prices

Similarly to figure 6.19, figure 6.20 shows the average price for down regulation. The figure also shows increasing down regulating price for increased volumes in balancing markets. Down regulation in week 9 is offered for less than 11 €/MW for all hours, but never 100 % freely . Down regulating is much more expensive in week 31, reaching 58, 71, 95 and 120 €/MW for 600, 900, 1200 and 1500 MW reserved capacity respectively at the peak at time step 4.

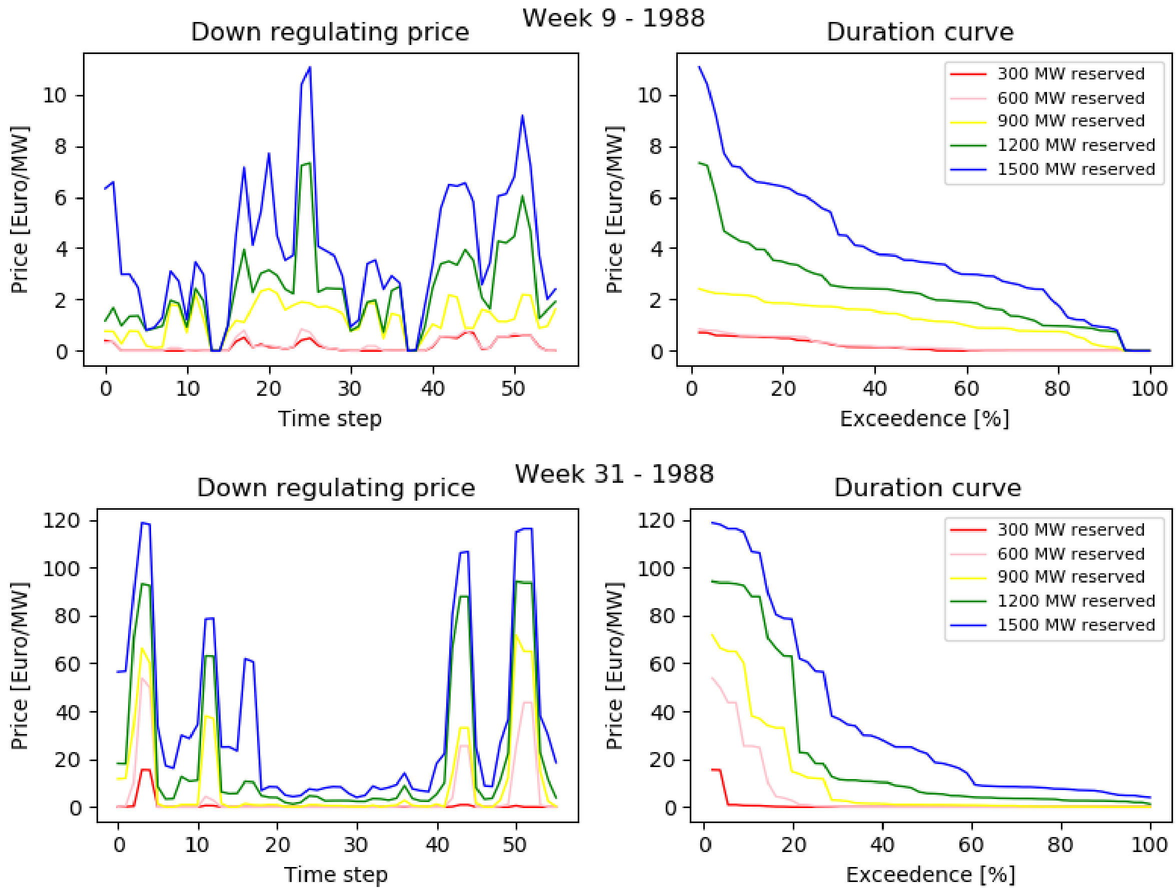


Figure 6.20: Case III: Average down regulating prices

Supplied reserves per area

As illustrated by figure 6.21, most of the Nordic areas will supply some up regulation in hour 38 of week 9. With a reservation of 300 MW, only Helgeland, Finland and Finnmark does not supply reserves. As the requirement increases, the supply also increases from each area with the Norwegian areas reaching its maximum supply first. An interesting observation can be seen in Vestsyd, where the are supplies some up regulation when 300 MW is reserved, than zero when 600 MW are reserved and then increases again for the remaining simulations. Also, it can be observed that Danm-ost is forced to supplly up regulation for all levels of reserve procurement with zonal reservation.

From figure 6.22 it can be observed that it is the areas dominated with thermal production (Denmark, Sver-syd, Sver-midt and Finland) supplies down regulation when the requirement is low. As the requirement increases, most areas start supplying or increases their supply unless they are supplying at their maximum capacity. Moreover, it can be observed that Sver-midt and Finland supplies most up regulation in all simulations.

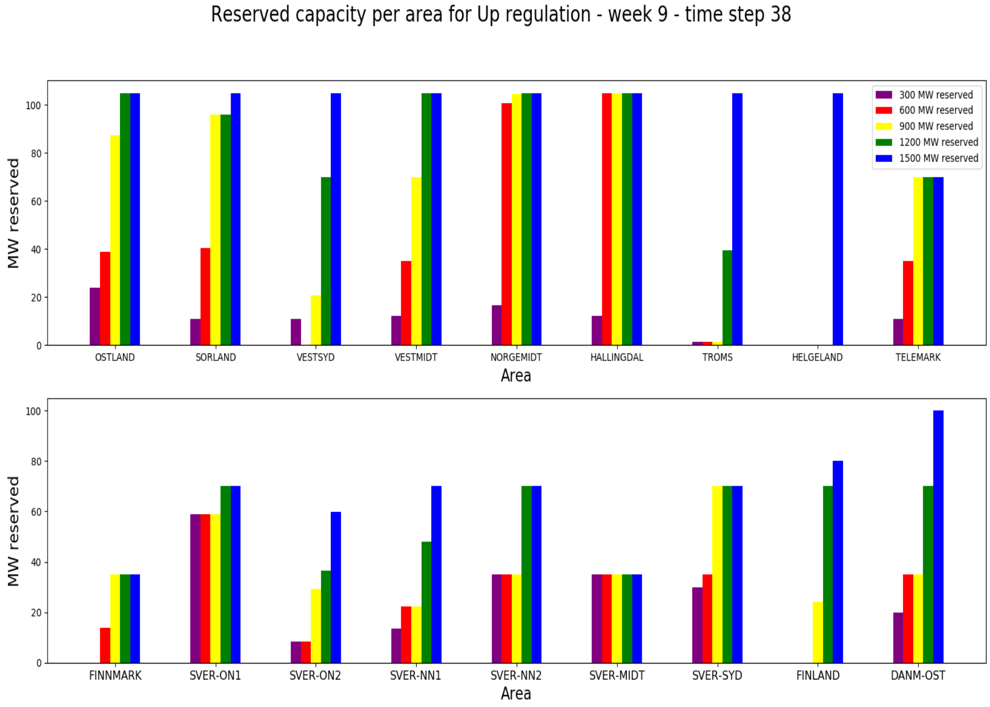


Figure 6.21: Case III: Reserved capacity for up regulation per area in week 9 time step 38

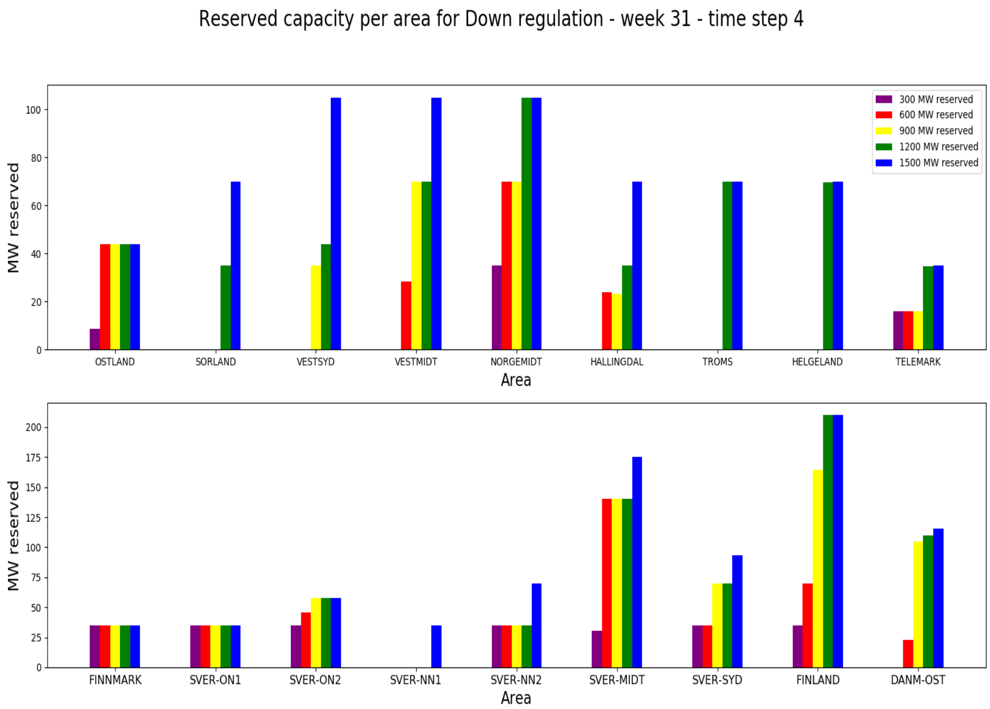


Figure 6.22: Case III: Reserved capacity for down regulation per area in week 31 time step 4

6.3.2 Market cross

Changing supply of reserve procurement

For case III, reserves are procured within each area. Consequently there will be a market clearing for reserves per area representing the supply and exchange of reserves in addition to the area requirement. In figure 6.23, the supply of reserves is plotted for different values of reserve procurement. Do note that this is not the market clearing as it represents the supply of reserves from the entire Nordic region and not for each area. The figure shows all the steps supplying reserves in time step 38 and 4 of week 9 and 31. Since the plot does not represent the market clearing, the reserve price is not found where the colored line crosses the gray line with similar pattern as it did in figure 6.12. The dotted gray line represents the reserve requirement, and the colored line with the matching pattern represents the supply of reserves associated with that requirement.

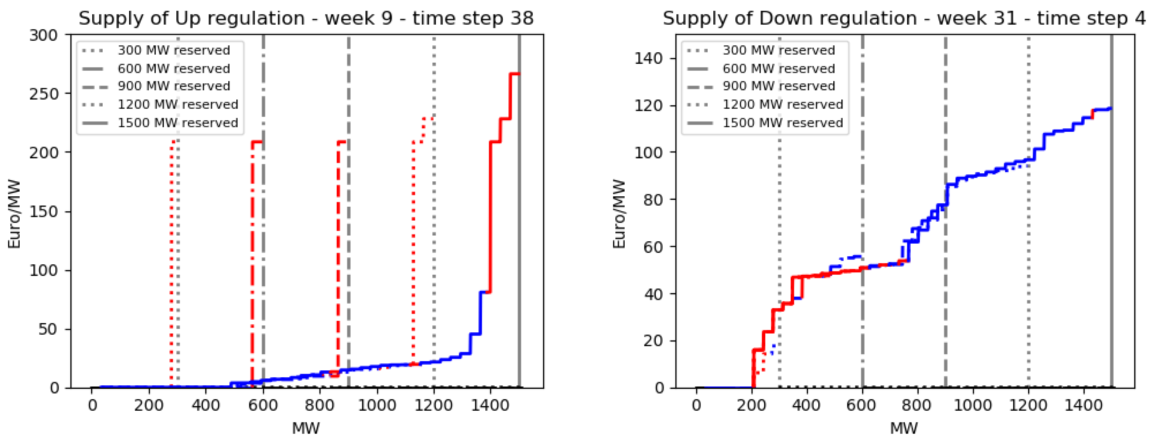


Figure 6.23: Case III: Changing supply of reserves for increased procurement

For week 9, figure 6.23 shows that hydro power is able to cover most of the reserve requirement. More expensive thermal units are turned on to deliver reserves as the requirement increases. Furthermore, a thermal unit with reserve price of 200 €/MW is turned on for all requirements for up regulation. This is a result of the zonal procurement of reserves. As there is limiting exchange capacity between the areas, production within each area that not otherwise would deliver reserves, may be forced to supply. This is the case in East Denmark in time step 38 of week 9. Import of reserves is set to its maximum capacity, in addition to limited available capacity in the area. Resultingly, a thermal unit with very high reservation cost will supply the area in all scenarios.

In week 31 it can be observed that thermal units cover most of the reserve requirement up to 1000 MW, whereas the peak capacity reservation is covered by expensive hydro power. The hydro power gets expensive during summer as reservoir level and inflow decrease resulting in high water values. When hydro turbines are forced to run, at low efficiency and at lower prices than optimal, the down regulating price gets very expensive.

Changing supply in the energy market

Figure 6.24 and 6.25 show how the market clearing for energy change when the reserve requirement increase from zero to 1500 MW in week 9 and 31 for some selected areas. For Ostland, Hallingdal the price cross is plotted, in addition to a graph zoomed to highlight the price deviations in week 9. The market cross is also plotted for Sver-midt and Danm-ost. The dotted line represents the supply when 1500 MW is being reserved and the straight line represents the the supply and demand with no reserve procurement.

Figure 6.24 shows how the supply changes at the peak in week 31. It can be observed that in Danm-ost and Sver-midt, the supply is actually shifted to the left at the same time as the price decrease. This is result of forcing in more thermal production, hence reducing import. The thermal units supply even though their marginal costs are over the area price. Resultingly, the area price can not be read where supply and demand cross.

From the graphs in 6.25 it can be observed that the prices increases when higher shares of up regulation is procured in the balancing market. Furthermore, the graph illustrates how generation from hydro power units are supplied at higher costs when 1500 MW is procured than in the base case.

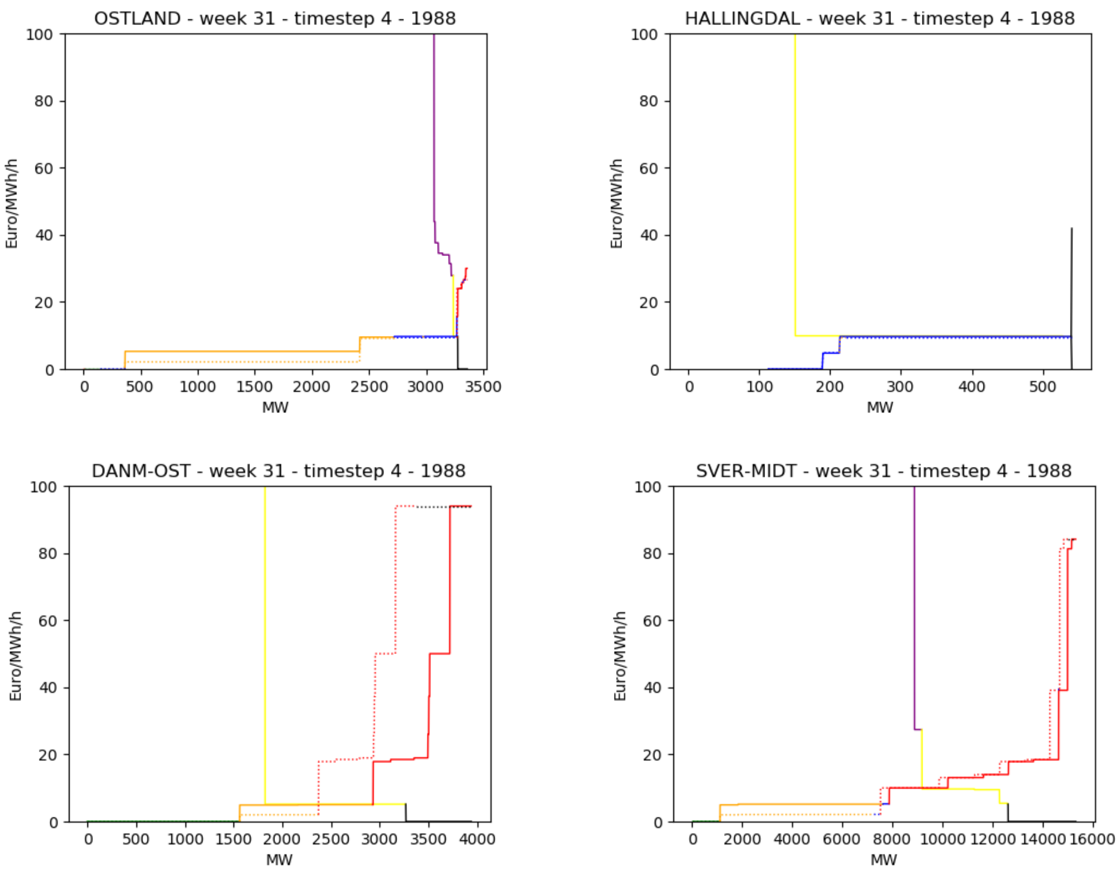


Figure 6.24: Case III: Changing market cross for energy in week 31

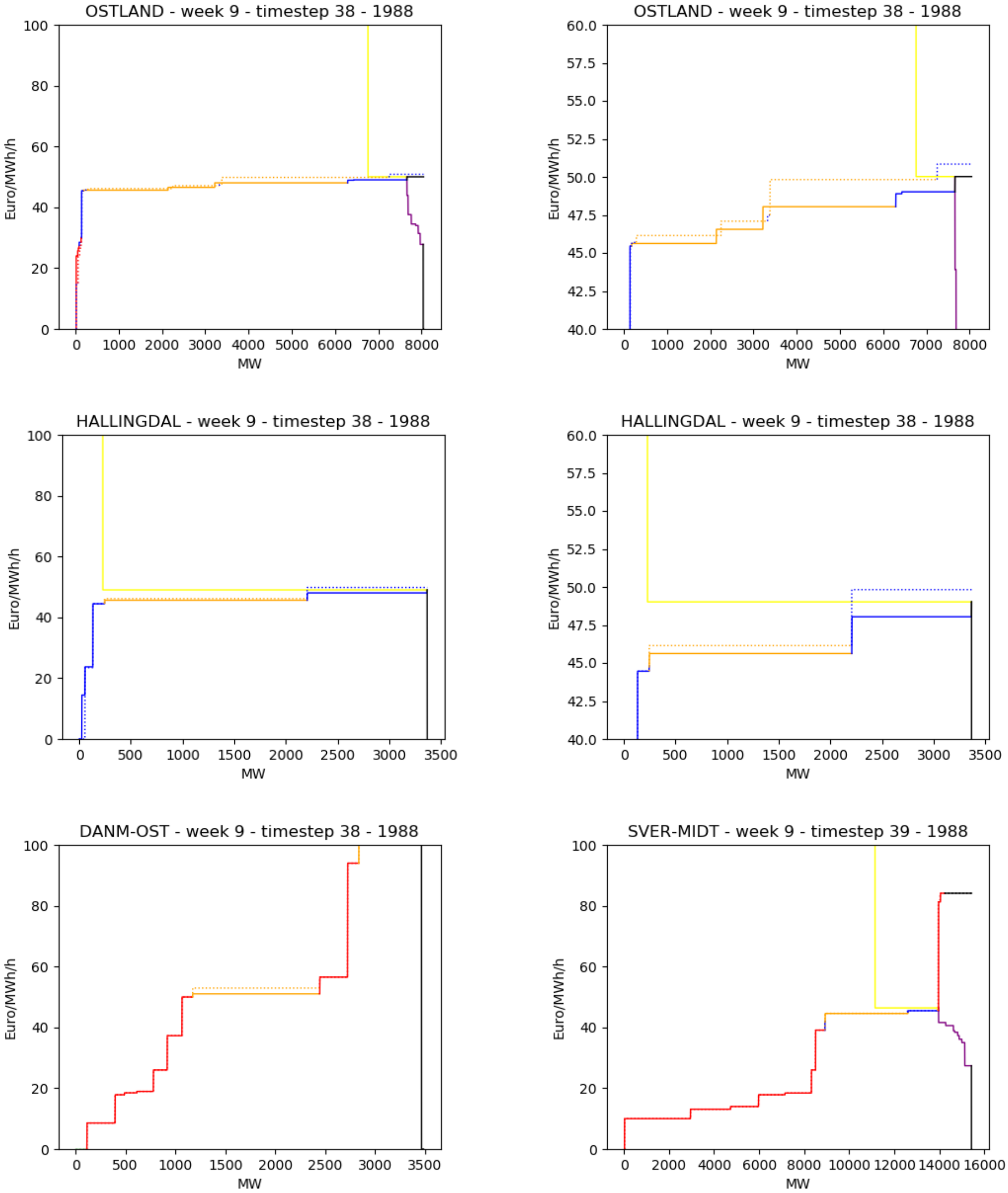


Figure 6.25: Case III: Changing market cross for energy in week 9

6.3.3 Economic surplus

Total surplus

In case III, the total producer surplus increase in week 9 for increased reserve procurement and decrease in week 31. The exception is when 1500 MW is reserved in week 9. This result can be blamed on decreasing area prices when down regulation is binding and will be further discussed in chapter 7.3. The consumer surplus follows the opposite trend, decreasing for increased reserve procurement in week 9 and increase in week 31. Again, the scenario with 1500 MW reserves deviates by increasing the consumer surplus compared to the scenario with 1200 MW reserved in week 9. Congestion rent slightly increase in both week 9 and 31 for increased reserve procurement except for the scenario with 1500 MW reserve procurement in week 31. The small deviation can be a result of more transmission capacity reserved for up regulation, reducing the net exchange in the power system.

Week	Reserved	Surplus [million €]			
nr.	effect [MW]	Producer	Consumer	Congestion	Total
9	300	1112,06	16995,66	86,44	18194,15
9	600	1112,11	16995,60	86,45	18194,16
9	900	1112,80	16994,87	86,53	18194,20
9	1200	1113,87	16994,18	86,65	18194,70
9	1500	1112,54	16995,68	86,79	18195,01
31	300	733,47	14091,24	44,61	14869,32
31	600	731,89	14092,46	44,90	14869,26
31	900	730,96	14093,17	45,19	14869,31
31	1200	729,09	14095,19	45,48	14869,75
31	1500	729,00	14095,67	45,03	14869,70

Table 6.5: Case III: Total surplus

Producer surplus

Table 6.6 shows the distribution of producer surplus per technology. It can be observed that the surplus from hydro power is lower in week 9 than in week 31. Moreover, table 6.6 illustrates that producer surplus increase for increased reserve procurement in all technologies except for wind/PV and thermal surplus in week 9 with 1500 MW procurement. Oppositely, producer surplus decrease for all technologies in week 31 except a slightly increase i hydro power surplus in the scenario with 1500 MW reserve procurement.

Week nr.	Reserved effect [MW]	Producer surplus [million €] Hydro	Thermal	Wind/PV
9	300	1,96	546,84	564,72
9	600	1,98	546,87	564,73
9	900	2,27	547,23	564,77
9	1200	2,82	547,65	564,86
9	1500	3,47	546,63	563,91
31	300	5,60	370,21	358,72
31	600	5,51	369,87	357,56
31	900	5,51	369,37	357,13
31	1200	5,30	368,50	356,34
31	1500	5,53	368,40	356,13

Table 6.6: Case III: Distribution of producer surplus per technology

Reservation costs

The reservation costs observed in table 6.7, illustrates increased reservation costs for increased procurement. Week 9 has the highest up regulating costs while week 31 has the highest down regulation costs. Combined, week 31 has the highest costs for both up and down regulation as down regulation is much cheaper in week 9 than in week 31.

Week nr.	Reserved effect [MW]	Reservation costs [million €] Up reg.	Down reg.
9	300	0,03	0,00
9	600	0,06	0,01
9	900	0,13	0,15
9	1200	0,86	0,36
9	1500	13,13	0,76
31	300	0,00	0,03
31	600	0,04	0,52
31	900	0,12	1,61
31	1200	0,15	4,33
31	1500	7,59	8,90

Table 6.7: Case III: Reservation costs

Figure 6.26 and 6.27 illustrates the geographical distribution of the reservation costs. In week 9, Ostland, Danm-ost has the highest reservation costs for all scenarios. When 1500 is procured, the areas dominated with hydro power, Hallingdal, Helgeland, Norgemidt, Vestmidt and Vestsyd has high costs in addition to Danm-ost. The reservation costs consists primarily of the up regulating costs, with very low down regulating costs. The down regulating mainly has costs in Ostland, Sver-midt and Sver-syd. In week 31, both up and down regulation get costly for 1500 MW of reserve procurement. Many of the areas has higher up regulating costs than down regulating costs in the case with 1500 MW reserved. Moreover, Sver-midt, Finland and Danm-ost has the highest costs for down regulation.

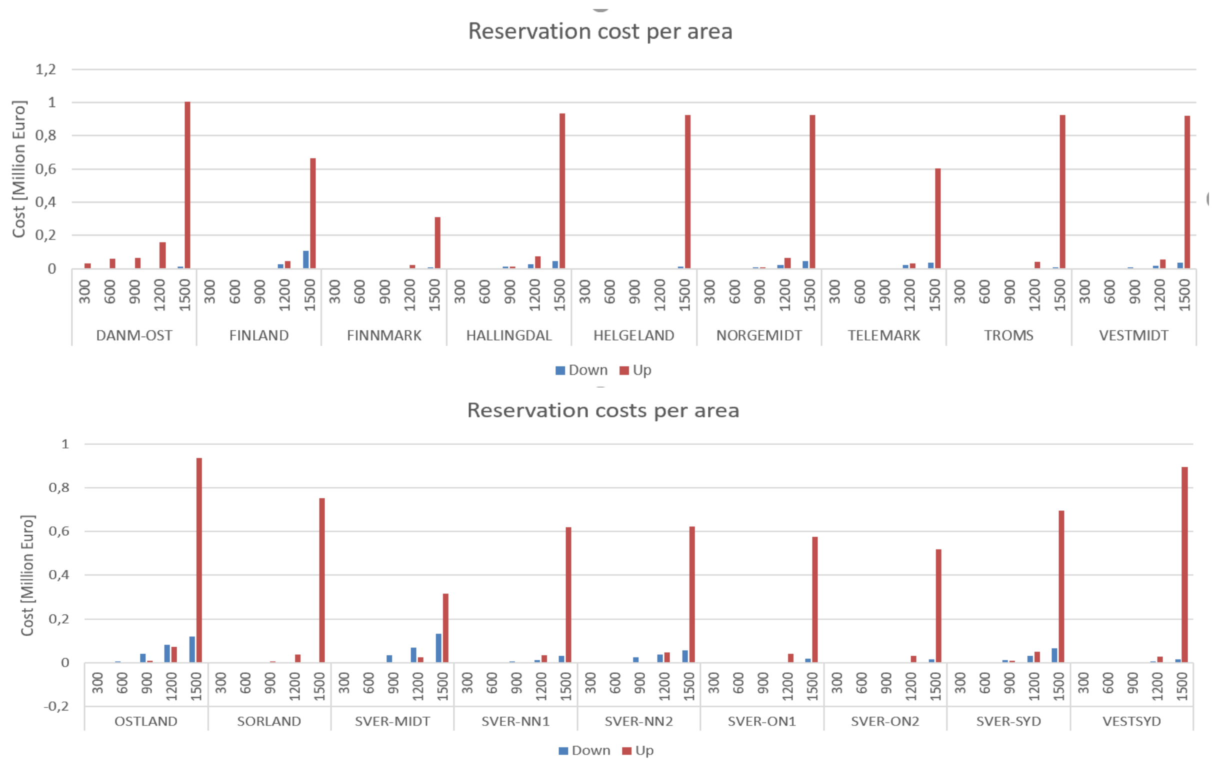


Figure 6.26: Case III: Distribution of reservation costs in week 9

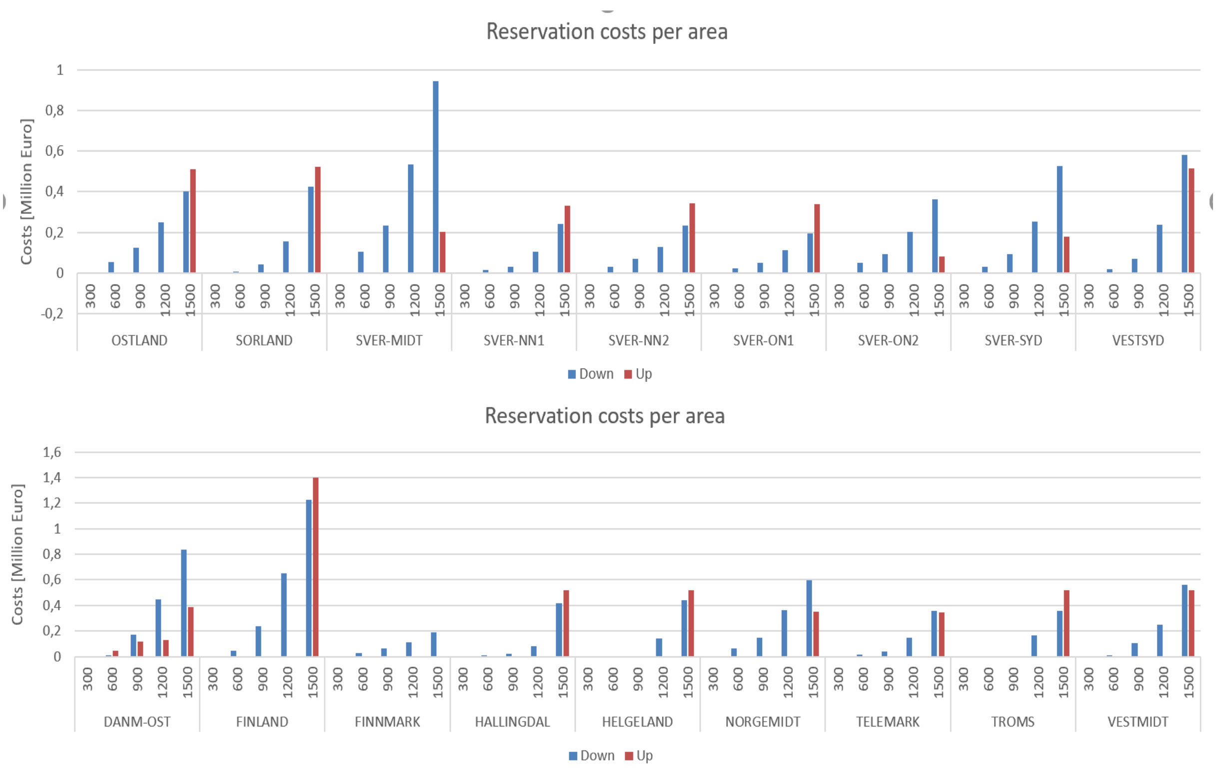


Figure 6.27: Case III: Distribution of reservation costs in week 31

Chapter 7: Discussion and comparable results

This chapter will compare and discuss the results found in the case study. Particularly results regarding the model response, economic surplus and reservoir handling will be discussed. Lastly, the validity and limitations of the model presented and analyzed.

7.1 Model response

Base response

The natural response of PriMod without adjustments from the author indicates that the model responds as expected. The area price is mostly affected by the load and the type of production. This is seen in both week 9 and 31. In week 31 the price reach very low values when the power production from wind and PV reach its highest values. Both week 9 and 31 covers most of the load from hydro power. The price is lower during the summer week than the winter week, which is expected as the load also is lower. As the model does not include ramping on thermal units, there is some overestimation of the model flexibility. This can be observed in figure 6.2 where the thermal power production can drop from 9000 MW to 8300 MW in one time step. However, as the time resolution in the model is three hours, the effects on ramping may be less significant as the model has three hours to shift its production/exchange. The time resolution may also lead to a poor reflection of the model response as what happens within the time resolution can be regarded as a black box. Particularly, in the hours where the load is changing before and after the peaks, important details may be left out as result of the high time resolution. Moreover, the time resolution in the day ahead market is one hour and is planned to change to 15 minute intervals. Case I only considers the trading of energy and therefore aims to reflect the response in the day ahead market. For accurate modeling of the day ahead market, it should be considered to use similar time resolution. As a shorter time resolution will lead to a higher computation time, results should be compared to find the optimal time resolution that provides sufficient details without increasing the computation time to much.

Area price

The key observations regarding the area price from case II and III, is that the area prices generally increase for higher shares of volumes reserved for up regulation and decrease for higher shares down regulation. The down regulating effect is most prominent during winter when the load is high, while the up regulation affects the area price most during summer when the load is low. As described by chapter 2.3.2, this is expected. For up regulation, capacity is removed from the energy market, increasing the power price. Down regulation on the other hand will increase the supply in the energy market by forcing some dispatchable generation to produce hence decreasing the energy price.

In week 9 at time step 38, the average area price is actually lower when 600 MW is reserved than when 300 MW reserved in case II. This is unexpected as we would expect the price to increase in this case. In the case study, the same volume is reserved for both up and down regulation for all hours. This could lead the results to not follow the expected trend as up and down regulation affects the price oppositely. Figure 6.8 and 6.9 shows that both 300 and 600 MW up and down regulation is supplied freely in week 9 for case II. It could have been argued that the deviation in price was a result of activated down regulation in week 9, but as down regulation also is supplied freely for both 300 and 600 MW, the argument is invalid. As neither reservation constraints are binding, one would expect similar power prices. However as the prices differ, one must investigate the underlying cause for the deviation.

This deviation could be explained by how the model handles its reservoirs. The simulations show that more generation originates from hydro power in the scenario with 600 MW than in the scenario with 300 MW reserve procurement. In addition, less water is bypassed when 600 MW is procured. More produced hydropower can be a result of lower simulated water values, the dual value of the reservoir balance. As the costs of water originates from the benders cuts, which again is as a function of reservoir level, lower water values correspond with fuller reservoirs. As we can see less that less water is bypassed, this may be the reason why the water values and production increase. As more power is produced, the water values will again rise as the reservoir level decrease, hence increasing the water values. Since the two scenarios has different distribution of water, the reservoir volumes are different at time step 38 when the area prices differ. This can explain the deviation in price between the case with 300 and 600 MW reserved. Moreover, regarding the areas supplying reserves at time step 38 in figure 6.10, it can be observed that Sver-NN2 supplies reserves in scenario 300 and not in the scenario with 600 MW reserved in case II. It is therefore clear to see that the model distributes the reserves in a different manner even though none of the reservation constraints are binding. As Sver-NN2 only supplies reserves from hydro power units, it can therefore be concluded that the reservoirs are handled differently in the two scenarios. From one of the reservoirs supplying up regulation in time step 38 in Sver-NN2, the water value decrease from 50 to 43 €/MWh, explaining the deviation in price as the water value decrease. That the average area price is lower when 600 MW is reserved can also be observed through the welfare considerations. When 600 MW is procured in case II, the consumer surplus decrease. Since the consumer surplus only depends on the area prices, rationing cost and load, the increased consumer surplus must be a result of a decreasing area prices as rationing costs and load are constant.

Reserve prices

The reservation costs are higher in case III than in case II and the reservation prices increase for increased procurement. This is to be expected as the cross zonal reserve transmission is restricted whereas case II has free flow of capacity within the Nordic region. If there were unlimited transmission capacity of reserves or if the reservation constraints were non-binding, the prices would be equal. As case III generates a market clearing, hence a reserve price, for each price zone, the reserve price is not set by the most expensive supplying unit in the system as in case II. Resultingly, some areas will have increased reserve prices whereas other will have decreasing. The average reserve price in case III is generally higher than in case II. However, when the price reach its maximum, the average reserve prices in case III are sometimes lower than in case II. This can be observed in figure 7.1 for week 9 at time step 12 for 1500 MW reserve procurement. This is a result caused by isolating the areas where the price is high. For example in case II, the up regulating price in the entire system during the peak was set by a thermal unit in Finland. In case III, the same unit only sets the price in Finland, and the remaining areas have lower up regulating prices, hence lower average up regulating price.

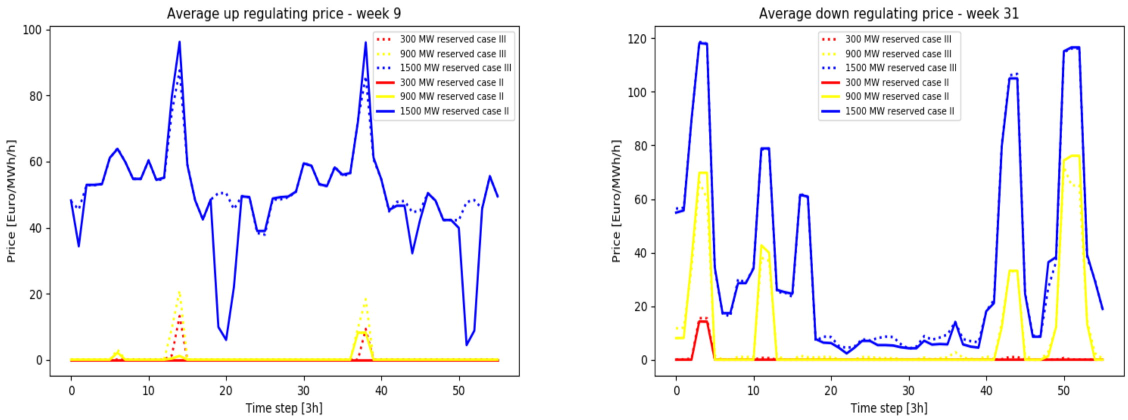


Figure 7.1: Compared average prices for up and down regulation

Changing supply of energy and capacity

By regarding how the supply curve in the energy market changes at peak hours, both case II and case III shows increased prices for up regulation. It also illustrates that the supply from hydro power has higher costs, hence higher water values, when 1500 MW is procured compared to the base case. This illustrates how the reservoirs are handled differently. The supply curves are not necessarily shifted to the left when 1500 MW is procured even though capacity is removed. This is because exchange and hydro power costs may differ when comparing the scenarios. It can also be observed that some production in Hallingdal is offered at a lower marginal cost when 1500 MW is procured than in the base case. The explanation for this is the model forcing bypass of water to be able to supply sufficient up-regulation in connected reservoirs. Resultingly, 30 MW is supplied at a negative water value.

For down regulation, prices slightly decrease in case II when 1500 MW is procured. The change is larger in case III when the reserves are procured within each price zone. The supply curve is actually shifted to the right but at a lower cost in Danm-ost in week 31 in case III. This is because the thermal units are forced to supply even though the price is under its marginal costs. Resultingly, thermal production replace import in the base case.

Regarding how the reserves distribute in peak hours, the Norwegian areas Vestmidt, Norgemidt and Hallingdal will start supplying first when 300 MW are required in case II. With free flow of reserves in case II, the areas dominated my thermal capacity as Finland, Sver-midt and Danm-ost wont have to provide any up regulating capacity until 900 MW is required. Danm-ost never provide any balancing capacity for up regulation in week 9 in case II. However, in case III this changes. As the case requires that each area must balance itself and limits the cross zonal exchange capacity of reserves, more areas will start supplying reserve capacity. This is particularly observed in Danm-ost which starts to supply up regulation for all required volumes in case III whereas it would supply none in case II. This can both be observes in figure 6.22 and 6.23.

When regarding the market clearing for reserve procurement for up regulation in figure 2.2 in case II, the last supply step determines the reserve price in time step 38 in week 9. Comparing this to the up regulating price in figure 6.8, the prices are equal. As observed from the reserve market cross, thermal units steps in to supply the requirement of 1500 MW. These are situated in Finland, and represents the supplied capacity as described in figure 6.10.

7.2 Relation to Hasle Pilot

In the literature review in chapter 2.1, the Hasle pilot was mentioned. The pilot tested the effect of cross zonal reservation of capacity. One of its results were that a reservation of 100 MW up regulation between a Swedish area and a Norwegian area would be available free of charge for 70 % of the time in its simulations. Similarly to the Hasle pilot, case III also implements cross zonal capacity reservation. Case III shows that up to 900 MW up regulation can be supplied freely 90 % of week 9 and if 1200 MW were reserved, it could be supplied for less than 12 € /MW also 90 % of the week. As the simulations in this thesis considers the capacity exchange between 18 areas in addition to having different data input and time horizon, the results are not directly comparable. However, it does highlight how PriMod could be used in providing an interesting tool for analysis of multi market modeling. To analyze cross zonal capacity exchange, the Hasle pilot took use of two methods to calculate the reservation prices, in addition to assuming that the reservation would have no impact on system prices. At the case results show, increased shares of reserved capacity highly affects the power prices and has to be included for price forecasting reserve price. PriMod could offer this service, without the assumptions made in the Hasle methodology. The assumption of no price impact from reservation, is only valid in hours with a surplus of generation capacity hence no impact on the energy price. As it is expected that a higher share of capacity is reserved for balancing markets in the future, this assumption would make the results regarding the forecasting of reserve prices in the Hasle pilot invalid. Therefore a model accounting for the deviation in price is necessary and PriMod shows promising results in serving as such a model.

7.3 Economic considerations

One of the key observation from the economic considerations is that the consumer surplus decrease for increased amounts of reserve procurement in week 9 and increase in week 31 for both case II and III. The reason for this is because the area price increase for increased amounts of reserve procurement from up regulation in week 9 and decrease for increased amounts of down regulation in week 31 as explained in section 7.1. Since the dataset only represents small amounts of flexible loads, the consumer surplus primarily depends on the area prices, rationing cost and load. The change in consumer surplus is therefore a result of the changing area prices as the rationing cost and load are constant for all cases. The exception to this trend is the consumer surplus in week 9 in case II when 600 MW is procured and in case III when 1500 MW is procured. In those cases the consumer surplus increase as a result of a reduced area prices. For the case with 600 MW procurement this can be clearly observed at time step 38 in week 9, where the price is lower than in the case with 300 MW procurement.

The producer surplus behaves in the opposite manner. Generally, the producer surplus increase in week 9 and decrease in week 31 for increased amount of reserve procurement. The exception to this trend is when 1500 MW is being procured in week 9 in case III. In that case, the producer surplus decrease compared to the case with 1200 MW reserved capacity. The explanation for this deviation can be that both up and down regulated is reserved at the same time. In case II, it does not affect the result as the system is less bound by the down regulating constraint . However, in case III when 1500 MW is being reserved for both up and down regulation, some units are forced to supply at a lower price then desired, pushing the price and the producer surplus down. This can also be observed in the consumer surplus, which actually increase in that case. When comparing the duration curve for down regulation in week 9, it can be observed that case III has higher down regulating prices. Consequently, case III is more bound by the down regulating constraint than case II. Resultingly, the area price decrease in the periods with little load, resulting in a lower energy price than when 1200 MW is reserved.

The producer surplus can be observed in detail in table 6.3 and 6.6 which shows distribution of producer surplus per technology. What is interesting here is that the producer surplus from hydro power is almost doubled in week 31 compared to week 9 even though the hydro production is lower. This is because the calculation of producer surplus from hydro power takes the area price minus the simulated water value times the production to compensate for the future costs of water. In the the applied methodology to calculate economic surplus in the EMPS model, Samoverskudd (14), the producer surplus from hydro power is found by multiplying the area price with the power production, disregarding the future costs of water. This is because the real ”cost” of producing hydro power is zero, as inflow is free. However, Samoverskudd analyzes a longer time horizon and does therefore not need to compensate for the future cost of handling the reservoirs in a different manner. Only regarding a short time horizon, PriMod must account for the future operating costs. Resultingly, the increased producer surplus in week 31 is a result of a larger deviation between water values and area prices in the producing modules. The income to the hydro power producer is not necessarily larger in week 31, but the future costs in the producing reservoirs are lower. This may be a result of fuller reservoirs or higher inflow in week 31.

Even though the consumer and producer surplus change as expected compared to the theory, combined, the total surplus does not seem to consistently decrease for increasing reservation requirements. This contradicts basic optimization theory which claims that a more strict constraint, will worsen the total welfare. The objective of PriMod is to minimize the costs, which corresponds to maximizing the total welfare. Resultingly, the total surplus should decrease for increased reserve procurement. The same result should be found when comparing case II and III. One would imagine that case II with reservation within the Nordic region to have a higher total welfare than case III with reserve procurement within each area. However, this is not the case. In the objective function, penalties are also included to avoid spillage, bypass and tanking. Since the different cases handles reservoirs differently such penalties could result in cases achieving higher total welfare and lower costs as penalties are inflicted. Generally, the consumer surplus is higher in case II in week 9 and in case III in week 31. This is expected as the area price is lower in case II in week 9 compared to case III and similarly in week 31 in case III. Comparing the producer surplus between the two, there is no clear trend. One possible explanation for this lay in the costs of hydro power. As the different scenarios handles reservoirs different, the valuation of water is affected differently. Resultingly, the simulated water values are different in the two cases. This is also seen in the market clearings for energy, which clearly show that hydro production is supplied at different water values for different volumes of reserve capacity. When calculating the producer surplus from hydro power, accounting for the future costs, the producer surplus may increase as a result of lower simulated water values in cases we would expect a lower producer surplus. As the costs change in the different cases, the total surplus will be affected. Furthermore, the valuation of water is calculated by the benders cuts provided by the strategic part, FanSi. This part should be simulated with the same data input as the operational model. However, FanSi is not run with reservation of capacity and this may lead to an overestimation of the cuts, leading to inaccurate valuation of water. This may also lead to a wrongful representation of the hydro power costs, resulting in an wrongful estimation of producer surplus from hydro power.

7.4 Validity and limitations

Reservoir handling

To compare how the model handles reservoir in the different cases, module 20100 is chosen for its interesting proprieties. This module corresponds to reservoir KRV Ritsem in Sver-ON1. Figure 7.2 and 7.3 shows how the water value, reservoir volume, production, and reserves prices evolve during week 9 in 1988. The graphs shows the results for all the cases with 600, 900 and 1500 MW as procured. The dashed line represents case II and the dotted line represents case III. The base case is represented with a drawn line.

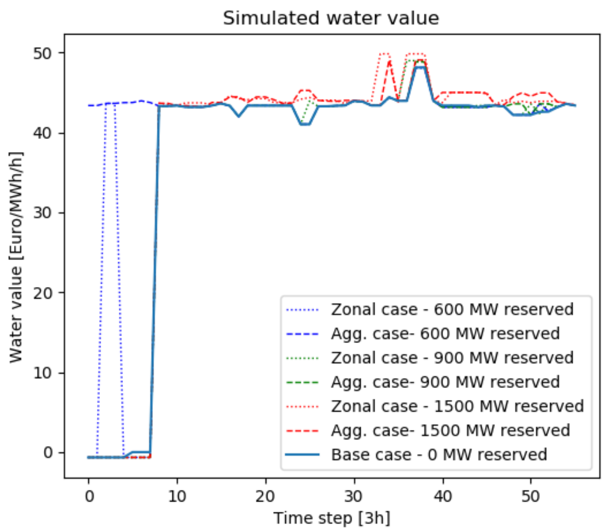


Figure 7.2: Development of water values in KRV Ritsem in week 9

First of all, in figure 7.2, it can be observed that the water values start with negative values in case II and III with 900 and 1500 MW reserved. This is a result of the model bypassing water to a connected reservoir supplying up regulation. To provide sufficient up regulation, without breaking constraints, the system is forced to bypass water. The production curve in figure 7.3

shows that the module is run on maximum capacity in all cases until time step 10 when the reservoir is emptied as shown in the graph representing the reservoir volume. That the reservoir empties from 120 Mm3 to 0 Mm3 is unrealistic and should be addressed in future versions of the model.

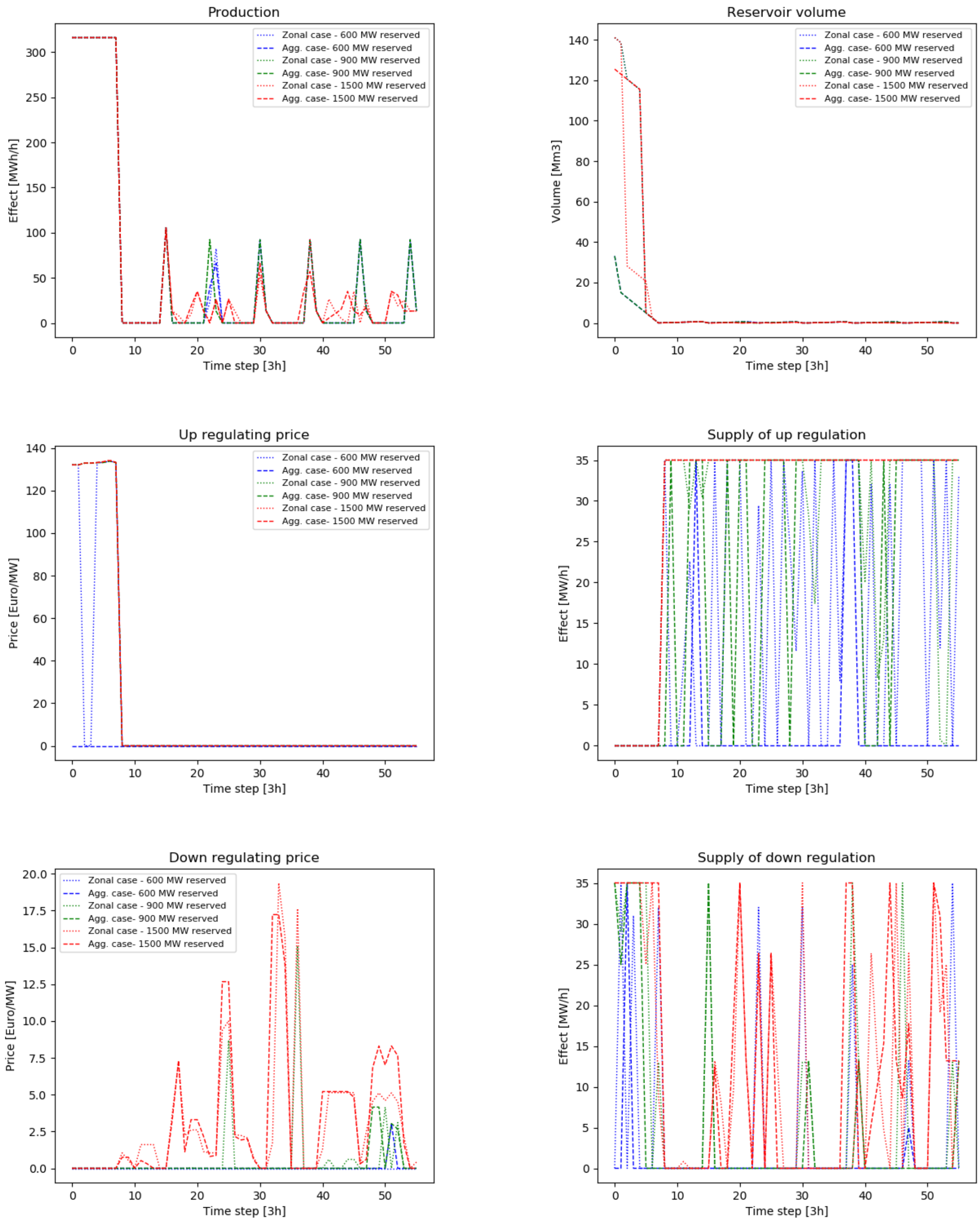


Figure 7.3: Reservoir proprieties week 9 in KRV Ritsem

The individual cost for up regulating this reservoir is quite high until time step 8 and therefore the reservoir does not supply up regulation until after time step 8 when the cost of reservation is zero. In the case with 600 MW reserve requirement the up regulating price is zero in case II and shifts between 0 and 130 in case III. This shift is a result of when bypassing water in an other manner than the other cases.

As seen by the graphs, the supply of up and down regulation shifts periodically from zero to maximum bid from one time step to an other. The reservoir supplies up regulation even though the reservoir is almost empty. When the reservoir is producing power, it also supplies down regulation. The fact that the supply of regulation can shift from 0 to 100 % from one time step to an another might be an overestimation of the system flexibility. As the balancing capacity markets are cleared before the energy market, the capacity is more often reserved over a longer period of time. Such fine time resolution of holding back capacity would make it much more complicated for the TSO insure enough capacity in the balancing markets and to validate that all capacity is available. As the time resolution utilized in the simulations, one could argue that the supply of regulation could be representative, however the issue should be addressed in further versions of PriMod.

In addition, as the supply graph for up regulation show that the reservoir can deliver up regulation even though the reservoir is almost empty. Some restriction regarding supply of reserves and reservoir volume should be included to achieve more realistic results.

Lack of more detailed modeling

As illustrated by figure 7.3, it could be claimed that this version of PriMod overestimates the flexibility in the power system. By not imposing enough constraints regarding the more detailed nature of reserve procurement, the model tends to supply reserves in an unrealistic manner, e. g. delivering up regulation with an empty reservoir and the sporadically reserving capacity. As the time step in the simulation is three hours, it could be sufficient with no minimum procurement time depending on the requirements in the market structure. However, it should be addressed in future versions of PriMod, how long a supplier of capacity reservation should hold back effect. An other concern regarding the modeling of reserves is the deliverance of up regulation with empty reservoir. If the power generation is zero, PriMod still allows the generator to reserve up regulating capacity. This poorly reflect how the power system operates, as the generators then would supply effect on a very low efficiency if activated. In addition, it would allow the generators adjust its generation from zero to five MW, which in reality is a highly unlikely situation on big turbines. First of all, the turbines would deliver at very low efficiency and second they would be run on very little water. Moreover, PriMod does not consider the losses in the water ways making it unattractive for hydro producers to reserve capacity without producing any thing. It should therefore be considered if PriMod should include a restriction on minimum production to supply up regulating capacity or if MIP programming should be introduced to insure that the the generator is on while reserving up regulating capacity.

Lastly, PriMod does not consider the activation of reserve procurement. In reality, the the reserved capacity would be activated by the TSO in the RK market for mFRR or through an automatic algorithm in aFRR. In situations with activated up-regulation, the reservoir level would then decrease as water is released from the reservoir. Similarly, the reservoir level will increase when down regulation is activated as less water is released. Resultingly, PriMod overestimates the reservoir level during the winter and underestimates the reservoir level in the summer. A consequence of this is wrongful valuation of water, as this is a function of the reservoir level. To compensate for the deviation in reservoir levels, it could be added a compensation for activation in the reservoir balance. The compensation would be added if the reservoir reserved capacity in the last time period.

Limited market participants

To enable the fundamental modeling of the balancing capacity markets, all market participants should be described correctly. In this thesis, the demand is modeled as firm with some instances of flexible industry loads in the Nordics. In the future power system, it is expected that consumer flexibility will play a bigger role. This is difficult to model as there yet is little empirical data on how this will develop. As the reservation of effect will have an impact on prices, and that it is expected that the future power system will be more price sensitive, consumer flexibility should be included in a larger degree. In addition, new technology like control systems and battery banks may allow consumer flexibility to participate in the balancing markets. Such technology is already on the market and being tested in pilot projects. Tibber and Voltalis examples on two companies supplying such services. The version of PriMod in use does only consider reservation of capacity from larger hydro power and thermal units. This leads to an underestimation of the system flexibility as it leaves out important sources of flexibility. Today consumer flexibility is allowed to participate in the RKOM market, though the strict terms in practice only allows larger industry loads to participate. The terms and conditions in the balancing markets are being reviewed to compensate for the increased need for flexibility and to enable an European platform to exchange balancing services as described by chapter 2.2. To achieve a more accurate fundamental optimization of the future power system with increased amounts of effect reserved in balancing markets, consumer flexibility and battery banks should be considered.

Relation to power markets

In PriMod the balancing capacity market and the energy market is cleared at the same time assuming all units defined for reserve procurement will supply if found optimal for the power system. It assumes perfect competition an rational market participant. The supply of reserve capacity is decided from a view of minimizing the system costs, e.g. maximizing the total welfare. In reality, the balancing capacity markets are cleared before the energy market. In addition, supply of reserve capacity is calculated trough non fundamental models optimizing the portfolio of the power producer. Their objective is not to minimize the total system costs and resultingly they may chose not to supply reserve capacity in a case where the PriMod would chose to supply. Overall, this leads to an overestimation of the available reservation capacity in PriMod.

Furthermore, PriMod does not consider the relation to other related power markets. Particularly, the RK-market is disregarded as activation of reserves is excluded. Resultingly, the reservoir volumes will deviate from actual values as activation is not accounted for. Moreover, the income a producer would receive from an activation of up regulation is ignored, underestimating the producer surplus.

Sources of error

The main source of error in this thesis is faults potentially executed by the author. The version of PriMod provided is complex and consists of over 2000 lines of coding. Errors may have occurred in the code handling and implementation of own data.

Furthermore, the units supplying reserve capacity is picked out by the author based on reservoir size and production capacity. As the modules providing reservation of effect are confidential, a mismatch of modules is likely. Therefore, PriMod does not reflect the actual response of the Nordic power system and the results would have been more accurate with the relevant reservation units. This will affect how the economic surplus distributes as the modules providing reserve procurement will be distributed in a different manner. The results of the model is therefore to be regarded as a possible system response illustrating how PriMod can provide multi market modeling and economic considerations.

Chapter 8: Conclusion and further work

8.1 Conclusion

This master thesis has utilized and further developed a prototype for fundamental multi-market modeling of a hydro-thermal power system. Constraints regarding reservation of capacity for both up- and down regulation has been implemented. A case study is performed and tests different allocations of capacity reservation. First, capacity reservation with an aggregated distribution level is tested followed by a zonal distribution level. Furthermore, a tool for economic considerations regarding the distribution of producer and consumer surplus has been created. All relevant coding will be available for future students and academics in agreement with NTNU and SINTEF Energy Research.

The following conclusions can be drawn from this master thesis:

- The area prices increases for increased amounts of up regulation when load is high and decrease for increased amounts of down regulation when the load is low. Similarly, the reservation prices for up regulation are high when load is high and the prices for down regulation are high when load is low. The simulations show that increased shares of reserve procurement has a significant impact on energy prices, underlining the need for a fundamental multi-market model.

- Allocating reserves within each price zone results in higher area prices for increased amounts of up regulation and lower area prices for increased down regulation compared to an allocation within a larger geographical area. The results show that the the zonal allocation will have a larger impact on both reservation prices and area prices, resulting in less reservation supplied freely.

- The economic surplus mainly changes as a function of the area prices. That includes higher consumer surplus and lower producer surplus when area prices decrease. However, there is some overestimation of the producer surplus from hydro power as the costs changes when the reservoirs are handled differently, this must be further investigated.

- PriMod sets a good framework for fundamental multi-market modeling, but need to include more details regarding the physical system on units supplying reserve procurement to enable more realistic results. The applied version of PriMod tends to overestimate the system capacity to deliver reserves compared to the actual nature of the power system. Particularly when regarding the frequent variations of supply from single reserve units and that non generating hydro power modules are able to deliver up regulation reflects unrealistic modeling of reserves.

8.2 Future work

On the basis of the thesis results, further work is needed to achieve more realistic results. The further work consist of more detailed modeling and a wider analysis to address the shortcomings of the model and verify the results. Some suggested implementations are listed bellow:

- Perform an economic analysis with a longer time horizon to test how PriMod responds over time.
- Implement minimum supply time for up and down regulation to reflect more realistic modeling of the reserve markets.
- Implement restrictions regarding minimum hydro generation on units delivering up regulation.
- Implement activation of reserves or adjust the reservoir volumes to account for activation of up/down regulation.
- Change to 15-minute time intervals for better handling of system variations.
- Implement reserve procurement in the strategic part for more correct valuation of water.
- Implement ramping on thermal units to avoid overestimation of system flexibility.
- Increase the share of flexible loads and allow battery parks and consumer flexibility to participate in the balancing markets.
- Further investigate how the future costs of water is affected by reserve procurement.
- A sensitivity analysis should be performed to test how the power system responds to reserve procurement under different conditions e.g more renewable, higher transmission capacities ect.

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Siri Hartvedt Norden

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Norwegian University of Science and Technology