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Optimizing weekly hydropower scheduling in a future power system

Development of a deterministic short-term
hydro-thermal scheduling model

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Preface

This master thesis concludes my Master of Science (M.Sc) degree in Energy and Environmental Engineering with the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). The thesis was completed in the spring semester of 2018, written under the supervision of Professor Hossein Farahmand and Ph.D. Candidate Christian Øyn Naversen with the Department of Electric Power Engineering at NTNU.

The topic of the thesis was brought up by my supervisor when an opportunity arose to cooperate with SINTEF Energy Research in relation to their project Pricing Balancing Services in the Future Nordic Power Market (PRIBAS).

I am deeply grateful to my supervisors for your guidance, support, and encouragement throughout the project. Furthermore, for taking the time to share your knowledge through engaging discussions and answering of my questions. I would also like to extend my gratitude to the researchers at SINTEF Energy Research participating in the PRIBAS project, for providing the PriMod model, for giving me insight to your work, and finally for supporting me in my own model development tasks.

Trondheim, 28-06-2018

Ada Elisabet Strand

Problem Description

The primary objective of this thesis is to continue the development of an intra-week short-term hydro-thermal scheduling model, PriMod. The model was provided by SINTEF Energy Research and is developed as part of their knowledge building project for the industry, PRIBAS. The model may be used by future Master's students and PhD candidates, under agreement with SINTEF.

The aim is to develop a model that efficiently handles a future power system, characterized by more interconnections, renewable energies, and uncertainties. The student will implement new constraints in the model to increase its modeling accuracy. The implementations are studied to gain insight to their effect on power system behavior.

The work-flow will look something like:

- Perform a literature study on energy markets
- Become familiar with the PriMod model
- Implement HVDC line ramping constraint
- Implement startup and shutdown costs for thermal units
- Implement a receding horizon method for mixed integer linear programming
- Study the effect of above implementations under different case studies

Abstract

In a future power system with high penetration of intermittent renewable energy sources, it will be necessary to adapt to their changes quickly to ensure system stability. In the European system, the Nordic hydro region could provide some of the necessary flexibility. For this to be possible, models used for hydro scheduling must be adapted to model a system with such variability correctly.

Hence, the object of this thesis is to continue the development of a deterministic short-term hydro-thermal scheduling model, PriMod. The aim is to create a robust model that handles the dynamics of a future power system. PriMod is developed at SINTEF Energy Research and has been made available for research at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). An approximating dataset *4del* covering the Norwegian power system with an interconnected thermal area is used for developments and investigations of the model.

The main contributions by the student are the implementation of; transmission ramping constraints, startup and shutdown costs of thermal units, and finally a receding horizon methodology for mixed integer linear programming (MILP).

Suggestions for further development of the model are presented, based on a high-level literature survey as well as case studies completed within the thesis.

The student's work on the model has been documented in BitBucket, to be traceable by future Master's students and Ph.D. candidates as well as researchers at the department, who wish to continue development of the model.

Sammendrag

I fremtidens kraftsystem med høy andel av ukontrollerte fornybare energikilder, må systemet kunne tilpasse seg raskt til endringene for å sikre stabilitet. I det europeiske kraftsystemet står Norges vannkraft i en unik posisjon til å kunne bidra med noe av den nødvendige fleksibiliteten. For at dette skal være mulig, må modeller for vannkraftplanlegging tilpasses til å modellere et system med en slik variasjon på riktig måte.

Derfor er målet med denne oppgaven å fortsette utviklingen av en deterministisk kortsiktig hydro-termisk planleggingsmodell, PriMod. Ambisjonen er å utvikle en robust modell som håndterer dynamikken i et fremtidig kraftsystem. PriMod er utviklet ved SINTEF Energiforskning og er gjort tilgjengelig for bruk ved Institutt for elektrisk kraftteknikk ved Norges teknisk-naturvitenskapelige universitet (NTNU). Et tilnærmende datasett *4del* som dekker det norske kraftsystemet med et sammenkoblet termisk område er brukt til utvikling og undersøkelser av modellen.

De viktigste bidragene fra denne oppgaven er implementering av; begrensning for flytendring på overføringskabler, start og stopp kostnader for termiske enheter, og til slutt en iterasjonsmetode med krympeende horisont for løsing av blandet heltall lineær programmering (MILP). I tillegg er det gjennomført studier av de overnevnte implementeringene.

Forslag til videreutvikling av modellen er også lagt frem, basert på en innførende litteraturundersøkelse, samt de gjennomførte studiene.

Studentens arbeid i modellen har blitt dokumentert i BitBucket, og kan spores av fremtidige masterstudenter og ph.d. kandidater samt forskere ved instituttet som ønsker å fortsette utviklingen modellen.

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Chapter 1 | Introduction

Though the future is unknown, there are strong indications for how the future power system will develop. Under the impact of European legislative packages, end-user requirements, technological developments and subsidized deployment of renewables, the European power system is undergoing important and rapid changes in the push towards a renewable power system.

The European Union (EU) has set ambitious goals towards 2050 to achieve at least 80 % reduction in greenhouse gas (GHG) emissions from 1990 levels to mitigate the effects of climate change. Achieving such aggressive goals is dependent on major transitions in all levels of the power system from generation through markets and transmission to the end-user [1].

Under the Renewable Energy Directive, the EU has committed to cover 20 % of its energy needs by renewable energy sources (RES) by 2020, and renewables will continue to be essential in the development past this point. At the same time, new interconnectors are built, making an integrated European system. Such a system will make it increasingly important to operate the systems optimally, and as the margins become tighter, smarter decisions must be made [2].

RES are intermittent and uncontrollable, making it necessary to respond quickly to their changes to ensure system stability. Simultaneously with the increase in RES, there is expected to be a decrease in thermal capacities due to decommissioning of nuclear and coal power plants. The combination of an increase of uncontrollable power and decrease of controllable power will escalate the need for flexibility and controllability. This need can be satisfied both in the generation and the demand side of the power system. On the generation side, hydropower could provide some of this flexibility. Therefore, the possibility of having Norway's hydro dominated power system act as a battery to Continental Europe, in various time horizons, has gained increasing interest in recent years. In order to enable this, the planning of hydropower generation must be improved and adjusted for the future power system.

Hence, the objective of this thesis is to continue the development of a deterministic intra-week short-term hydro-thermal optimization model, with applications in a future power system. The work builds on PriMod, developed by researchers at SINTEF Energy Research. The model is developed on a system level, with focus on the correct scheduling of hydropower generation resources. An approximating dataset *4del*, covering three Norwegian hydropower areas and one thermal area, is applied for the model development and investigations. Though the developed model is built for the Norwegian system, it could be used for any system if given the appropriate input data.

1.1 Related research studies

This literature survey focuses on studies from the Norwegian and Nordic system, as well as being limited to short-term hydro scheduling (STHS) and short-term hydro-thermal scheduling (STHTS) problems. First, sources that are related to the applied modeling approach are presented, moving on to cases that are relevant to consider for future developments of the model. Finally, work related to the study of a future European energy system are presented as well as an approach to reduce computation time for models.

In "Short-term hydro scheduling in a liberalized power system" [3], the authors present methodology applied in the short-term hydro scheduling problem, and address relevant challenges. The presented method of successive linear programming (SLP) with a deterministic problem formulation is widely used by power producers, grid operators, consultants and regulators in the Nordic system today. The conference paper lacks a mathematical formulation of the optimization problem, apart from the reservoir balance equation, which is considered the fundamental constraint of the system. Also covered is the method for coupling of the mid-term and short-term models through cuts, as well as methods and strategies for the producers to bid in the spot and real-time markets.

The same authors, who are researchers at SINTEF Energy Research, provide further insight to SLP with a deterministic model in ”Hydro power short-term scheduling in an on-line environment” [4]. Here they focus on system modeling by presenting both detailed reasoning and the resulting mathematical equations used for the model implementation. Start and stop costs, which are directly relevant to the thesis work are included. The model is developed to make detailed unit schedules in a cascaded river system. The authors also include a shorter description of the SLP solving strategy. Also considered are test examples, one of which considers the effect of start/stop costs. They find that including these costs cause a reduction in unit starts, causing almost 50 % decrease in system start costs. The model can be applied for decision support when bidding in a spot market, or to decide an optimal fulfillment of a given load obligation and to adapt to changed conditions.

The authors of ”Experiences with mixed integer linear programming based approaches on short-term hydro scheduling” [5] contributes a detailed introduction to the topic of mixed integer linear programming (MILP) approaches on the STHS task. The problem is formulated in 35 equations, each having a comprehensive description. The study period ranges from a few hours to seven days in hourly or half-hourly increments. The model is implemented with a relational database management system based graphical user interface and is solved using AMPL and CPLEX. The model has been tested with two actual hydro systems, resulting in near optimal solution in reasonable time. The model does not include thermal units, but can be treated as a sub-function for hydro-thermal coordination while a decomposition scheme applies.

Though most of the short-term models in operation in the Nordic system today are deterministic, studies of the past decade are focused on stochastic models that include uncertainties in market prices and inflows. ”Optimal bidding strategies for hydro-electric producers: A literature survey” [6] provides an overview of methods for the bidding and scheduling problems in hydro-thermal systems considering a deregulated market. They present methods based on the type of bidder considering whether they are a price taker or -maker, and whether they are a hydro- or thermal producer. The survey focuses on short-term models, which is the horizon where bidding occurs. This survey is not limited to cases considering the Nordic system.

The SHOP model described in [3] and [4], has been further developed in the stochastic direction as is described in "Applying successive linear programming for stochastic short-term hydro power optimization" [7], and is thereby transformed to SHARM. Here, the authors who are also researchers at SINTEF Energy, focus on the modeling of uncertainty. Their approach is to use scenario trees with deterministic equivalents for each branch to represent uncertainty in either market prices or inflow. The model was first tested in GAMS before it was implemented in C++ and as a prototype made available to the industry. The authors also include extensive case studies as well as a comparison between deterministic and stochastic models. They found that stochastic models provide more robust results than deterministic models, and expect the added value to increase with the combined uncertainties or prices and inflow.

[8] is another paper that focuses on developing a short-term production plan using a stochastic model, while [9] aims to offer the optimal bid curves from their stochastic model explicitly. Furthermore, there are many studies focused on the effect of a single system features. Such as; [10] on handling state dependent nonlinearities in tunnel flows, [11] on modeling minimum pressure height, [12] on water delay, [13] on the impact of maximum flow ramping rates, and finally [14] models a head-dependent cascaded river system with discharge ramping constraints and start/stop costs.

There are also many studies directed at the future European power system, where the use of Norwegian hydro reservoirs as a battery for the intermittent wind and solar production.

[15] applies stochastic optimization and simulation with an eHighway2050 scenario combined with increased hydro capacity in Southern Norway to study how the production patterns of plants, reservoir levels, and water values may be affected. The studies are performed using the EMPS model. They find that some plants utilize their increased capacities, while others do not due to hydrological constraints and model limitations. Water values and reservoir levels increase for 3 out of 4 areas, and there is a significant change in the production pattern with increased capacity.

[16] take the perspective of a hydropower producer in Southern Norway to consider the profitability of investing in pumped hydropower storage based on a 2050 price scenario. The authors consider sales in both the day-ahead and real-time markets. The scenario is implemented and studied in the ProdRisk model.They found that income increases

by 2.2 % by supplying balancing energy and in the day-ahead market, while the income increases by 21 % with the investment in pumped storage. Thus, participation in the European balancing markets can be decisive for the profitability of pumped storage in Norway.

[17] focuses on transmission expansion to enable the future power system with high penetration of solar and wind capacities. The authors suggest a two-step investment algorithm containing an iteration loop to identify profitable investments based on an operation optimization model, where the effect of the investments on the power market outcome is taken into account through the iterative process. The presented algorithm is used to analyze transmission expansion for a 2030 scenario in the Northern European power system and benchmarked against a 2010 scenario. They find that market prices increase significantly in Continental Europe as well as having much higher volatility. Furthermore, the hydro production becomes much more volatile illustrating its utilization to balance variable RES production. Finally, due to increased transmission to Continental Europe, the effect of inflow on Nordic electricity prices is significantly decreased. The study shows that there is a corridor from the Nordic region to Continental Europe and the UK that is profitable and necessary to expand.

[18] presents a review of state-of-the-art simulation studies on the use of Nordic hydropower for balancing and storage of variable solar and wind production. They evaluate twelve papers that study the need for balancing and storage, possible further developments in the Nordic power system, consequences of different market solutions, and changes in operation patterns of the Nordic power system. [17] is included in the survey, while [15] and [16] were not published at the time.

A widely recognized issue within hydro scheduling is the balance between problem detail and computation time. With the coming changes to shorter planning periods and increased variability, the systems are expected to become larger and more complex, requiring improvements within computational efforts. [19] studies the application of parallel processing to combat computation issues. They study the current use in models developed at SINTEF Energy, finding that it is particularly useful for stochastic problems. For the long-term EMPS model, and a medium-term deterministic model, the computation time has been decreased from several hours to minutes by applying one-level parallel processing. As one-level parallelization processing is coming close to its potential, they look to multilevel parallel processing to further decrease computation time while allowing for more detailed modeling.

1.2 Scope

Like the majority of research within the European power system, this thesis is focused on the future power system with significant penetration of variable wind and solar power generation resources. The presented work is part of the development of a short-term hydro-thermal optimization model for the future power system. For the time being, the problem is formulated as the deterministic equivalent to the stochastic reality but differs from other short-term models as it optimizes in detail for weekly steps with hourly resolution. The model is also developed using the open-source optimization software Pyomo that is implemented within the framework of Python [20][21]. The model is solved with Gurobi [22]. As the model is still under development, there is still room to define future developments and focus areas for the model.

The model is formulated on a system level, with internal prices calculated from the solution. It aims to produce dispatch for not only one river system, but the whole interconnected region of Northern Europe, in detail. Besides, the model must be robust to handle a dynamic problem, while also maintaining low computational time.

With this thesis, a new instance of the model is created for internal use by Master's student and Ph.D. candidates with the Department of Electric Power Engineering at NTNU, under an agreement with SINTEF Energy Research. The work by the author is in the NTNU instance and is not implemented in SINTEF's version of PriMod. For the remainder of this thesis, *the model* will refer to the NTNU instance of PriMod, unless otherwise stated. Also. PriMod-NTNU will be used to refer to this instance of the model.

As PriMod is proprietary for SINTEF, PriMod-NTNU is also considered confidential. Therefore, no excerpts from the code will be included in the thesis. However, a mathematical representation of the optimization problem solved in the model is included.

Objectives

Within the current framework and time available the objectives are defined as;

- Present a literature survey on energy markets
- Become familiar with PriMod
- Implement ramping constraints for HVDC lines
- Implement startup and shutdown costs for thermal units
- Implement receding horizon methodology for MILP
- Develop necessary datasets for case studies
- Investigate and compare results under case studies

The author wants to point out that studies are completed on a conceptual level and can not be considered indicative of future power system behavior. Moreover, they are used solely to study the behavior of the system under the author's implementations.

1.3 Outline

The body of the thesis is structured as follows;

Chapter 1 aims to motivate the thesis work, leading to the objective, and to efficiently limit the scope. The chapter provides an introduction to the topic of the thesis and develops a framework for the study through the presentation of relevant research.

Chapter 2 shortly presents relevant background theory on power markets and hydro scheduling and -modeling. The chapter is limited to focusing on what is directly relevant to the completed work.

Chapter 3 is a study of the *4del* dataset used for the model development, provided by SINTEF. The description has the purpose of providing insight to modeling decisions and inherent limitations.

Chapter 4 covers some relevant optimization theory and presents the optimization problem as it was formulated in PriMod when received.

Chapter 5 covers the main contributions of the author, through five case studies. Each case concerns one implementation or system change, with methodology, results, and discussion.

- *Case 1: Base-case* - Presents the model as it was upon reception. The case is used to gain familiarity with the model, and to identify necessary adjustments.

- *Case 2: Benchmark* - Is developed, with the inclusion of wind power production and increase in load, to have a more variable system for benchmarking. In addition, adjustments are made to some parts of the dataset that caused unusual results in the base-case.

- *Case 3: Ramping* - Describes and studies the contribution of ramping constraints.

- *Case 4: Start/stop* - Addresses the implantation of startup and shutdown costs for thermal units, as well as the implementation of receding horizon for the MILP.

- *Case 5: Future power system* - Is the final study of the thesis, developed to study the model under extreme conditions, and to verify that the model works as a whole.

Chapter 6 summarizes the findings of the studies of Chapter 5, by identifying adjustments that should be made to the current implementation, as well as recommending future developments in the model.

Appendix A contains tables with module ID to name references. It has been included to allow for assessment of the results while considering the topology of the modeled hydro system.

Appendix B contains results from each case that are relevant for comparison to other cases, but not relevant for the discussion of the considered case.

Appendix C presents, in short, the optimization software Pyomo and relevant information about the applied solver Gurobi.

Appendix D holds the mathematical formulation of the final version of PriMod-NTNU, as it is implemented today.

1.4 Contributions

The author's main contributions from this thesis are the model developments and the study of these, namely:

- implementation of transmission ramping constraint
- implementation of startup and shutdown costs
- implementation of receding horizon methodology

Chapter 2 | Theoretical background

This chapter covers relevant theoretical background, with the aim of developing the context which the masterwork has been completed within. The first section shortly covers power system & markets, with emphasis on Norway and and connected regions as well as expected future developments. Then moving on to the problem of hydro scheduling, where the short-term scheduling is most relevant for the work presented in this thesis. Finally, modeling of the physical hydro system is covered. The goal is that the reader will have sufficient understanding of the general context and methods used in hydro-thermal system optimization to understand the choices made in the modeling and analysis performed in this project work. Theory of optimization as a method is presented first in Chapter 4, where the optimization problem is also formulated mathematically.

2.1 Power system & markets

First, some necessary information about the Norwegian system is presented, establishing its importance in the European system. Then follows a section on the NordPool market, from which the presented principals apply to most deregulated markets. The section is closed off with a view at expected future developments, with developments affecting the Norwegian system being especially considered.

2.1.1 Norway

With approximately 96% of Norwegian electric power being provided from hydro plants, the Norwegian power system is in a unique position in the European system. The Norwegian electric energy production mix for 2016 is shown in Figure 2.1. The total Norwegian electricity production in 2016 was 149TWh, while the demand was 133TWh, allowing for 22TWh net export [23]. The figure clearly shows a hydro dominated production at 96.37% for the year.

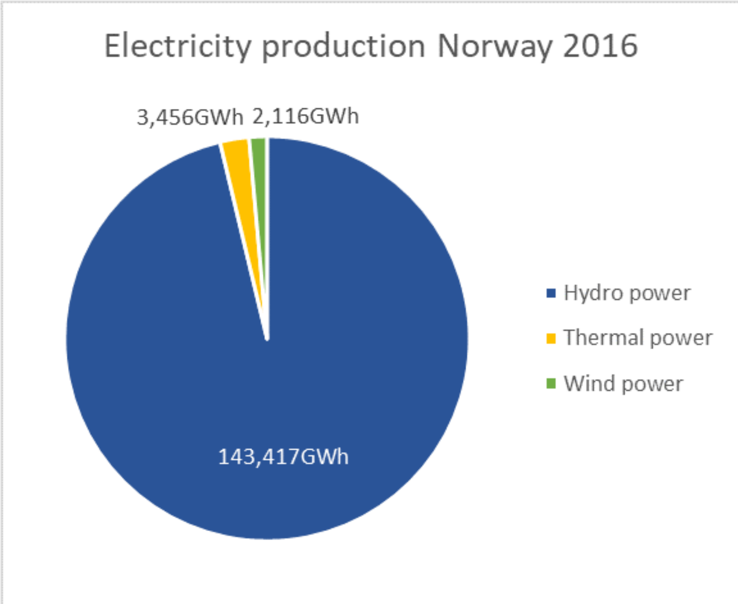


Figure 2.1: Electricity production in Norway 2016, by type.

Due to the possibility of storing water in the reservoirs (85TWh capacity), the Norwegian system has a high degree of flexibility. This and the fact that the production is from renewable energy places Norway in a unique position in the future as Europe's green battery. [24]

The Norwegian system is part of the Nordic power system with Sweden, Denmark, and Finland - connected through AC transmission. Power flows freely between these countries, and they have the same frequency. Additionally, the system is connected to Denmark and Netherlands through HVDC lines, and cables to Germany and Great Britain are under construction. This transmission capacity is shown in Table 2.1, totaling at 6095MW today and 8895MW by 2021 with the commissioning of NordLink (NL) and North Sea Link (NSL).

Additionally, a possible connector, NorthConnect, of 1400 MW is being considered to Scotland. Southern Norway usually has surplus energy and limited transmission capacities to other regions. The new interconnectors will thereby not only allow for the provision of balancing services but also provide security to the Norwegian system. This is especially important due to high variations in inflow between dry and wet years.

Table 2.1: Transmission capacity from Norway

Border	**Name**	**NTC export capacity**	In operation
Norway - Sweden	Several lines	3695 MW	Yes
Norway - Denmark	Skagerrak 1-4	1700 MW	Yes
Norway - Netherlands	NorNed	700 MW	Yes
Norway - Germany	*NordLink*	*1400 MW*	exp 2020
Norway - Great Britain	*North Sea Link*	*1400 MW*	exp 2021

Figure 2.2 also shows these overseas interconnections in southern Norway.

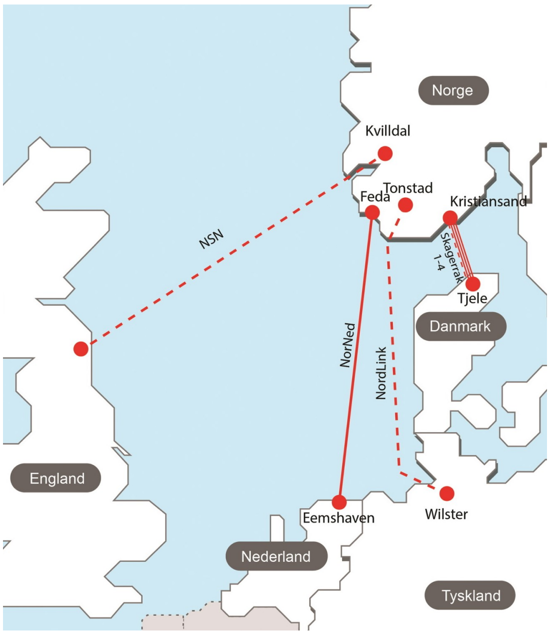


Figure 2.2: Existing and future HVDC cables connecting to Norway

The Norwegian electricity market was deregulated under the Norwegian Energy Act in 1991. Instead of being obligated to produce to the local geographical area to meet a load obligation, power companies could now produce for profitability [25]. Meaning that production changed from being controlled by the government to being determined by the producers, most of the power is traded on the common NordPool market which is introduced in the following section.

2.1.2 NordPool

The North European system is highly interconnected and therefore has a common trading platform for power, NordPool. Here, power can be traded on both day-ahead and intraday markets. Power trading is beneficial concerning system stability as it is possible to utilize the difference between the connected systems. Thereby one can achieve the same level of security at a lower cost, considering the system as a whole though locally the cost may increase.

In deregulated electricity markets producers optimize their production independently and must determine the optimal supply curve for maximal revenue. The supply curve expresses the willingness to produce a certain volume at a certain price - more is offered as price increases [9]. The producers send their bid to the day-ahead market based on this curve. Demand curves expressing the willingness to consume at a price are determined similarly. The market is then cleared, setting the system price using the market cross as shown in Figure 2.3. Supply above and demand below the crossing point will not be covered [26].

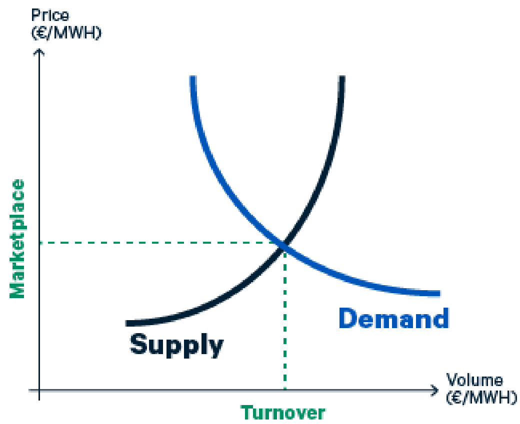


Figure 2.3: Market cross [26]

NordPool is Europe's largest arena for trading power, offering day-ahead and intraday trading. Day-ahead market power trading is available in the Nordics, Baltics, and UK. While intraday includes Germany, France, Belgium, Netherlands, and Austria as well [26]. 394TWh of power was traded in the Nordic and Baltic day-ahead market in 2017[27]. The share of production per country is shown in Figure 2.4, based on data downloaded from NordPool. It is clear that the Nordic countries are the most significant market players, with Sweden at the top ahead of Norway.

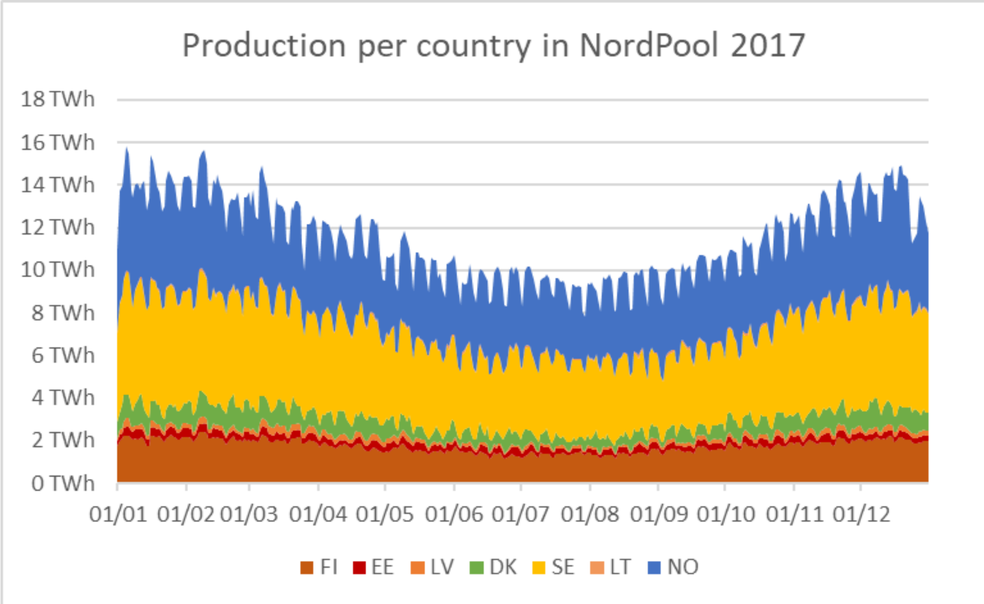


Figure 2.4: Production in NordPool 2017, by country[26]

2.1.3 Future developments

Though the future is unknown, there are strong indications for how the future power system will develop. Under the impact of European legislative packages, end-user requirements, technological developments and subsidized deployment of renewables, the European power system is undergoing important and rapid changes in the push towards a renewable power system.

The EU has set ambitious goals towards 2050, to achieve at least 80 % reduction in greenhouse gas (GHG) emissions from 1990 levels to mitigate climate change issues. Achieving such aggressive goals is dependent on major transitions in all levels of the power system from generation through markets and transmission to the end-user [1].

On the way to this change, the member countries of the EU have also committed to the Renewable Energy Directive with goals of reducing GHG emissions by at least 20 %, have a renewable share of at least 20 % of consumption and save at least 20 % of energy by 2020 [28]. According to the 2018 report "Renewable Energy Prospects for the European Union (REmap EU)" by the International Renewable Energy Agency (IRENA), the EU is on track to reach these goals at 23 % by 2020 and to reach 27 % by 2030 [29].

As the bulk of newly installed generation capacity in the EU is from RES, the fossil-fuel generation has stagnated or declined. The renewable technologies are becoming cheaper faster than expected, while the efficiency increases to give higher capacity factors. Fossil plants are then terminated as they are no longer competitive [29][30].

On the other hand, the RES that is nuclear is seeing a different development. Though the energy is clean and affordable, many countries have planned to decommission their nuclear plants due to security concerns.

The energy capacity mix for the EU in 2010 and expected levels for 2030 are shown in Figure 2.5, showing an increase in RES generation as wind capacities are built in the Northern part of the region and solar PV in the south. Furthermore, there is an apparent decrease in thermal capacities as coal and oil shale power plants, all nuclear plants in Germany and four nuclear reactors in Sweden are decommissioned. Some of the nuclear decreases are offset by the commissioning of two new reactors in Finland by the mid-2020's [29].

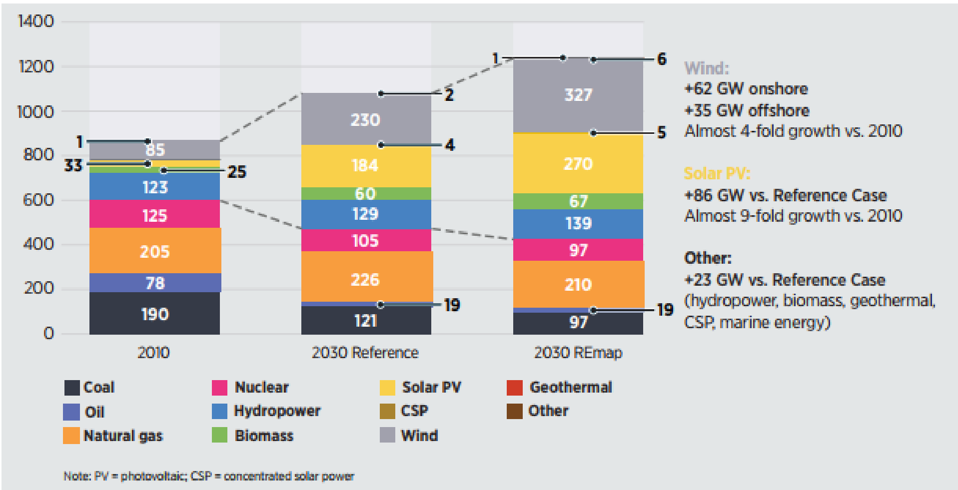


Figure 2.5: Expected development for generation capacity (GWh) [29]

Looking at how this affects the power system, there is a decrease in adjustable power concurrent with an introduction of more variable power. These changes make for a system that is more difficult to operate securely as the risk of power shortage increases. At the same time, the society is becoming more electrified and dependent on a secure supply to safeguard vital functions of society [30].

Hence, international power exchange becomes important to provide flexibility and dilute the renewable variations in a larger system. The main drivers for grid developments in the Baltic sea are:

- Nordic increase in energy surplus
- Integration of renewables

, which are the basis for developing the NL and NSL cables, and the considered development of NC. With a need for regulating power from the Nordic hydro system and extensive development of wind power in Northern Norway, it is expected that the flows from North to South will increase [30].

2.2 Hydro power scheduling

Hydropower scheduling consists of determining the optimal production strategy for a specified time horizon. The power producers try to maximize their profit while taking into account the risk. The scheduling is closely linked with optimizing the supply curves for day-ahead bidding which was discussed in Section 2.1.2, because the cost of hydro production is determined as opportunity cost [9]. For price-taking producers, it is optimal to offer energy at the marginal cost of production. However, this marginal cost is difficult to determine as precipitation is a free resource that only has a cost due to opportunity cost. The opportunity cost is expressed in the model through water values, a detailed description of how to compute them can be found for example in [31].

Hydropower scheduling is a complicated task, mainly because of time coupling and uncertainty in input data. Uncertainty in parameters like market prices and climate dependent input such as inflow should be considered. Furthermore, hydro systems can have a complex topology with many cascaded reservoirs and plants in the same river system. A detailed description of the system interconnections and water travel time is valuable to achieve realistic and implementable results. Also, the reservoirs vary in size, sometimes significantly. In these complex systems, the decisions made in one time step will limit the choices in later time steps. When the system, as in Norway, is interconnected with neighboring power systems with thermal production the optimization must be solved as a mixed hydro-thermal planning problem.

Hydro scheduling has a number of specific challenges that make hydro models necessary for decision support in operation and planning of the system:

- System size; computation time
- Shared ownership; multiple owners in the same river system
- Physical structure; topology, termination point, cascaded
- Constraints; physical and regulatory (difficult to implement since not quantifiable)
- Time horizon and step; long horizon combined with short step
- Uncertainty; market price, demand, inflow and fuel prices
- Data models; different models for each sub-problem, coupling difficult
- System borders; highly interconnected, where to stop

Because of this complexity, it is widely accepted that the full optimization problem must be decomposed into smaller, more manageable sub-problems as illustrated in Figure 2.6. The planning period is dependent on the system and more specifically the reservoir storage capacity. Participants will usually use a long-term, medium-term and short-term model, where each problem is solved with a dedicated solution technique [7]. This section covers a short description of how the three time periods over which we model, while background on solution techniques can be found in Chapter 4.

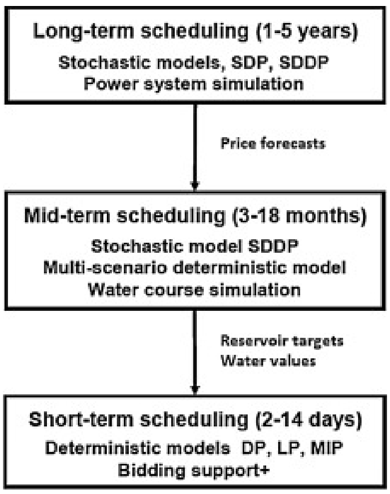


Figure 2.6: Scheduling sub-problems [7]

2.2.1 Long-term

The first step of solving the hydro-thermal optimization problem is to determine the optimal strategy in the long-term. These models are typically stochastic, accounting for uncertainty in the input variables for inflow and prices. The horizon is typically 1-5 years, depending on reservoir storage capacity. The producers use the result for scheduling their resources for sales in the market, or for price forecasting. Due to the system size and long time horizon, which is solved at weekly increments, these models use aggregated reservoir models to produce results within a reasonable computation time [3].

Statistics are used to represent the uncertainties in the system, e.g., in price and inflow. Forecasts for price, demand, inflow, outages, new installations, etc. play an essential role in the long-term scheduling. The optimization is based on expected future prices and thereby expected future revenue.

2.2.2 Mid-term

The mid-term model, also known as seasonal scheduling model, is used to link the short- and long-term models, due to incompatibility in their system descriptions. The time horizon is usually 3-18 months, solved at weekly increments, depending on system characteristics. The topology description is similar to the short-term, in order to supply suitable boundary conditions. Thereby, the mid-term model transforms the results from the long-term model to give correct impulses to the short-term model [3].

2.2.3 Short-term

The short-term model is the final, most detailed model that the producer uses to minimize the cost of covering load obligations or to maximize profit if a market is present. It requires detailed information about each reservoir and plant as a basis for optimizing the use of the individual resources. The coupling to the mid-term model is based on incremental water value description for the individual reservoirs. The short-term model focuses on the period where scheduling is to be implemented, so the horizon is one day to a few weeks at most. The model determines the actual production for the coming hours and days, with a rough solution for the rest of the period in case of operational issues to ensure the possibility of bidding. The results from the model are used to express the supply curve that bids to the day-ahead market are based upon, as discussed in Section 2.1.2.

The short-term model can include, e.g., startup costs, cascaded watercourses, transmission, and generation ramping, detailed plant efficiency descriptions, and various market constraints [7]. The time increment is chosen to suit the level of detail and the input data, usually market steps or hourly resolution. The system detail and time increment must be weighted against computation time.

Short-term models are usually deterministic, meaning that prices and inflow are assumed known for the whole optimization period. Scenario analysis can be used if a solution space is required, dependent on market and weather conditions [31]. Deterministic models allow for a higher level of detail in the system description.

The short-term models will usually solve for the period in daily increments. One or two days are modeled in detail to enable qualified bidding to the market, while a rough solution might be computed for a longer period in case of model failure. PriMod differs from other models in that it is intra-week; providing a detailed solution at weekly increments.

2.3 Hydro modelling

This section starts off with a simple description of general hydro modeling; modules, reservoir, topology, and inflow. Finish with modeling that is specifically relevant for the thesis, but not strictly necessary to model a system; startup and shutdown of thermal units and transmission line ramping. The goal is to give insight into how a model is built, and what information is required for modeling the system.

The level of detail for the modeling is dependent on the users and their needs. One must assess what information is available to the users, and its importance in the model against computation time. The detail is usually adjusted to the specific needs of the analysis, based on what the users wish to study.

This section is primarily based on the specialization project completed by the author in the fall of 2017, with some additions providing more details where relevant.

2.3.1 Module

The system is modeled through modules as shown in Figure 2.7 based on its plant, reservoir and hydraulic connections. For each module, regulated and unregulated inflow, and termination points for spillage, bypass, and discharge need to be provided. Water originating from upstream plants and reservoirs are included in the illustration in the regulated and unregulated inflow.

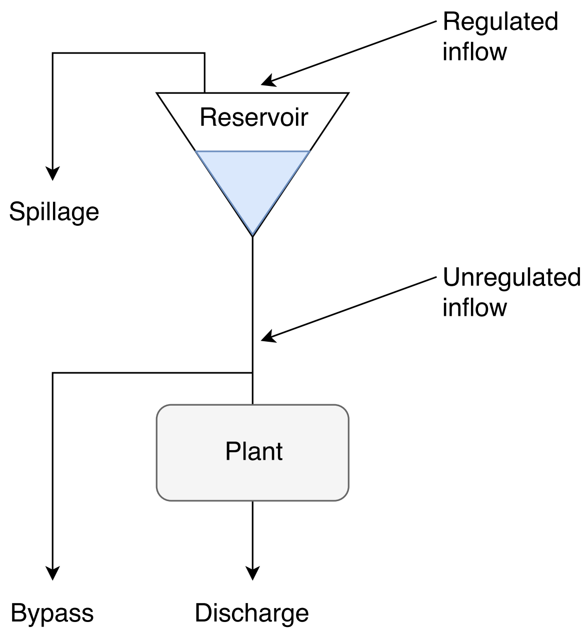


Figure 2.7: Hydro power module

A module can be a plant, reservoir, a combination of the two, or a point in a watercourse that is needed to specify a system constraint. A hydro system will typically consist of many interconnected modules, making their operation interdependent. Especially in the case of Norway, the hydro systems comprise complex river systems with multiple plants connected in series and parallel.

Short-term models include detailed descriptions of each module, consisting of a plant and a reservoir, as shown in Figure 2.7. There is detail on all inflow; regulated, unregulated, tunneling, pumping, as well as discharge, bypass and spilling from upstream reservoirs. Then all release; discharge, bypass, spilling, tunneling and pumping and their termination points are specified. Also, the module can include information about the head, the number of turbines and their efficiency- or PQ-curves.

2.3.1.1 Plant

The minimal data to be provided for a plant are its discharge capacity, m/s, and the average energy equivalent kWh/m^3. The energy equivalent determines how much energy is stored in each m^3 of water in the reservoir [31].

Different, more complex modeling can be implemented if desired. For example; internal waterways to calculate losses from the intake to the turbine, units within a plant for start/stop modeling and loss calculation, efficiency curves for units to model relationship between head and efficiency and tailrace for more accurate modeling for small reservoirs. Choice of constraints is also adjusted for the user's needs [4].

2.3.1.2 Reservoir

The challenge of hydropower scheduling is the control of the reservoir, which determines all other output variables. The capacity can vary from a few days of production to several years. The reservoir volume must always be specified; for plants with no reservoir, it can be set to zero. Further, some models require a reservoir curve to be specified which expresses the relationship between the water level and volume. If the reservoir curve and backwater level are known, one can calculate the plant head, giving more realistic results for the production. Most reservoirs and rivers have a lowest and highest allowed water level due to environmental constraints. In Norway, these levels are regulated by the Norwegian Energy Directorate (NVE)[1].

2.3.2 System topology

The systems under study are often cascaded river systems, comprised of many modules as described in the above Section 2.3.1. It is then necessary to correctly model the interconnection between these modules, regarding discharge paths. The systems quickly become complicated as the paths do not necessarily have the same destination, and because multiple plants can be fed from the same plant and vice versa. The topology of each area in the studied system is presented in Section 3.1.

[1] `https://www.nve.no`

2.3.3 Inflow

As previously mentioned we have storable and non-storable inflow. The non-storable inflow must be used when available, and if the inflow exceeds plant discharge capacity, the excess will be spillage. Inflow is specified by an average annual volume in Mm^3 and a reference that describes weekly and annual variations.

In the Nordic market, there is a strong correlation between the inflow and market price, while inflow is also the dominating source of uncertainty in the Norwegian system due to the large shares of hydro. In the period 1981-2010, the average inflow to the Norwegian system has been calculated to 130TWh by NVE. In the time period 1958-2012 the variation in the period has been of 75TWh, from 90TWh to 165TWh, the whole series is presented in Figure 2.8.

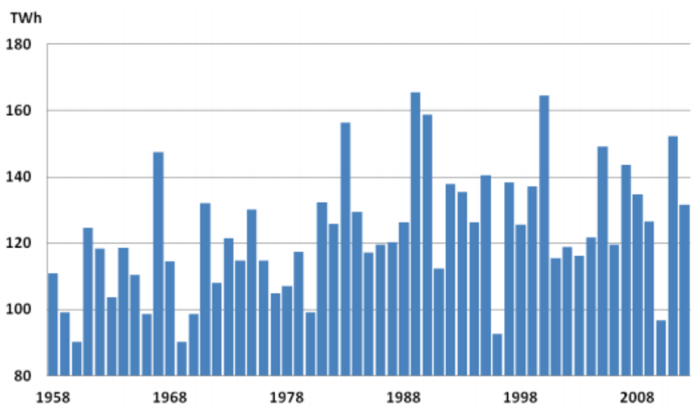


Figure 2.8: Usable inflow to the Norwegian system in the period 1958-2012 [32].

2.3.4 Startup and shutdown costs

Startup and shutdown costs can be implemented on thermal, hydro and pumping units to reflect the additional cost of starting or stopping the unit regarding fuel used or unit wear. For hydro units, the fuel cost would be lost opportunity cost in terms of lost water. However, these costs are rarely implemented for hydro units as they are difficult to quantify and significantly increase the computation time while the effect on the optimal solution is small as the cost is usually small. It is important to take into account startup and shutdown costs because the dynamic in a hydro-thermal system to a significant degree stems from the dynamics between high and low load conditions [33].

Table 2.2 contains an overview of the average startup and shutdown cost for different types of thermal plants in northern Europe. The table is generated from data used in the TWENTIES project[2], which aimed to advance the development of new technologies that facilitate the widespread integration of more wind power to the European system [34]. The dataset includes plants in; Sweden, Denmark, Finland, Great Britain, Netherlands, Belgium, and Germany.

Table 2.2: Average data on thermal plants in Northern Europe

Type	**Capacity**	**Running cost [€/MWh]**	**Startup cost [€] (cold)**	**Shutdown cost [€]**
Lignite	516	5	19172	2875.8
Nuclear	1097.4	9	-	-
Hard Coal	468.5	25.8	12281.0	1842.15
Gas	386.6	47.3	5047.7	504.7
Oil	280.2	94.9	10863.2	1086.32

2.3.5 Ramping constraints

HVDC lines, typically used to connect systems in different countries, are controllable and have a ramping limit. The limit implies that the flow on the line cannot be changed instantaneously. The limit is physical, related to how much change the power system can handle in a short period, and determines the volume and speed of change in flow on the interconnector. The Nordic system operators have stated that frequent substantial changes in the production and flow make it difficult to control the system frequency. Ramping restrictions are therefore imposed to reduce risks that might threaten the security of supply. Without ramping, extensive ancillary services and operational reserves would be required to maintain balance in the system [35].

An imbalance between generation and consumption causes the frequency deviations. These structural imbalances are caused by the current market design with hourly trade resolution and an agreement between the Continental European transmission system operators (TSO). Production plans and flows on interconnectors are changed around the hour shift; meanwhile consumption changes continuously through the hour.

In the current system, the flow on lines from the Nordic synchronous system can be

[2] `https://windeurope.org/about-wind/reports/twenties-project/`

changed within 20 minutes around the hour shift at a rate of 30MW/min, for a total of 600MW/hour. This limit is based on an overall assessment of the operational security in the area, and the potential accumulated imbalances that rapid changes in interconnector capacity may inflict.

The significant increase in interconnector capacity from Norway, coming with NL and NSL, will cause larger and more frequent changes in power flow on the interconnectors. The introduction of new cables might bring a requirement of lowering the limit to 400MW/h. Thus, the structural imbalances will increase, unless mitigation actions are effectuated. Changing to finer time resolution in the markets could decrease the imbalances already in the planning phase, as well as allowing for flow ramping every 15 minutes. Thereby, it might be possible to increase the hourly ramping limit to 1200MW [36]. The relative ramping for each of these cases, considering 700MW and 1400MW lines, is included in Table 2.3 for development of case studies.

Table 2.3: Ramping on line based on size

	Ramping, %	
Ramping	**700 MW line**	**1400 MW line**
400, MW/h	57.14%	28.57%
600, MW/h	85.71%	42.86%
1200, MW/h	171.43%	85.71%

Chapter 3 | Dataset

As previously mentioned, this master thesis is completed using a model and data provided by SINTEF Energy Research as a starting point. In this chapter, the input data is described to provide context for future analysis and discussion. The dataset is a simplified representation of the Norwegian power system that for example is used for model development tasks such as this one. The dataset is suited for use in the EMPS model. The aim of giving a detailed description of the data is to provide an understanding of how the model has been developed based on this, inherent limitations and to provide a clear understanding of the foundation for the presented work. Modifications made to the model as part of the work for this thesis are described in detail in Sections 5.1-5.5.

Description of the base dataset

The dataset used in this project work consists of four areas, approximating the Norwegian power system with an interconnection to a European area. The included areas are; Otra, Trondheim energiverk (TEV) and Numedal representing the Norwegian system, and Term which is a thermal area representing the connected Nordic and other European countries. This system is illustrated in Figure 3.1. From here on the dataset will be referred to as the *4del* dataset.

The Norwegian areas are hydro dominated, with TEV having hydro generation exclusively and Otra and Numedal with minor thermal capacities. The area Term has only thermal capacities. *4del* has been developed with the intention of studying the Norwegian power system; this area is therefore considerably larger regarding generation capacity and load than Term. Essential load and generation figures for the system are shown in

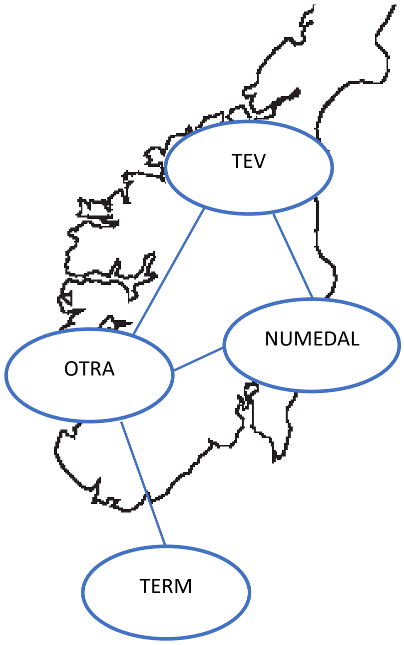


Figure 3.1: *4del* system

Table 3.1.

Table 3.1: Generation capacity per area by type

	NUMEDAL	TEV	OTRA	TERM
Number of hydro modules	17	12	21	-
Hydro production capacity, MW	610	535	820	-
Reservoir storage capacity, Mm^3	931	1382	1947	-
Number of thermal units	7	0	6	5
Thermal production capacity, MW	5.12	0	<0.1	280-310
Minimum load, MW	204	107	114	97
Peak load, MW	525	434	640	145

3.1 Hydro system

The greatest strength of the *4del* dataset is the detailed description of the Norwegian hydro system. It includes detailed topology, plant characteristics as well as inflows.

Modules

Plant descriptions include; piecewise linear PQ-curves, generation efficiency per curve segment $MW/m^3/s$, head, maximum/minimum discharge per segment m/s, relative head as well as limits and penalties for bypass, spilling, and discharge, $m^3, e\,/Mm^3$.

The reservoir descriptions include absolute limits on reservoir capacity, Mm^3, minimum reservoir level, Mm^3, and a start reservoir level, Mm^3. Additionally, there are variable limits on maximum and minimum reservoir levels, Mm^3. Finally, cuts limiting the end of week water value are provided for each reservoir. Only reservoirs $\geq 0.1Mm^3$ are included in the model.

As the model is deterministic, there is a need for limiting the end of week solution space. This is done through cuts that for example can supply acceptable ranges for the end of week water values or reservoir levels. Cuts used in this model are provided by SINTEF and have been generated with the SOVN/FANSI model.

Topology

The hydro system topology is described in detail with destination for tunneling, spilling, bypass, and discharge. Additionally, each flow has maximum and minimum allowed levels of flow, either based on plant characteristics or regulations by NVE.

Figure 3.2 - Figure 3.4 show the structure for each area in the *4del* system. Sea indicates that the water is lost from the system, not available for production further down in the river system. *b*, *s*, *d* indicate bypass, spilling and discharge respectively. The reservoirs are shown with name and storage capacity, Mm^3, while plants are shown with name and generation capacity, MW. Tables A.1-A.3 in Appendix A relate each reservoir and plant to a module, which can be useful as a reference for the reader in the system studies in later chapters Chapter 5.1-5.5.

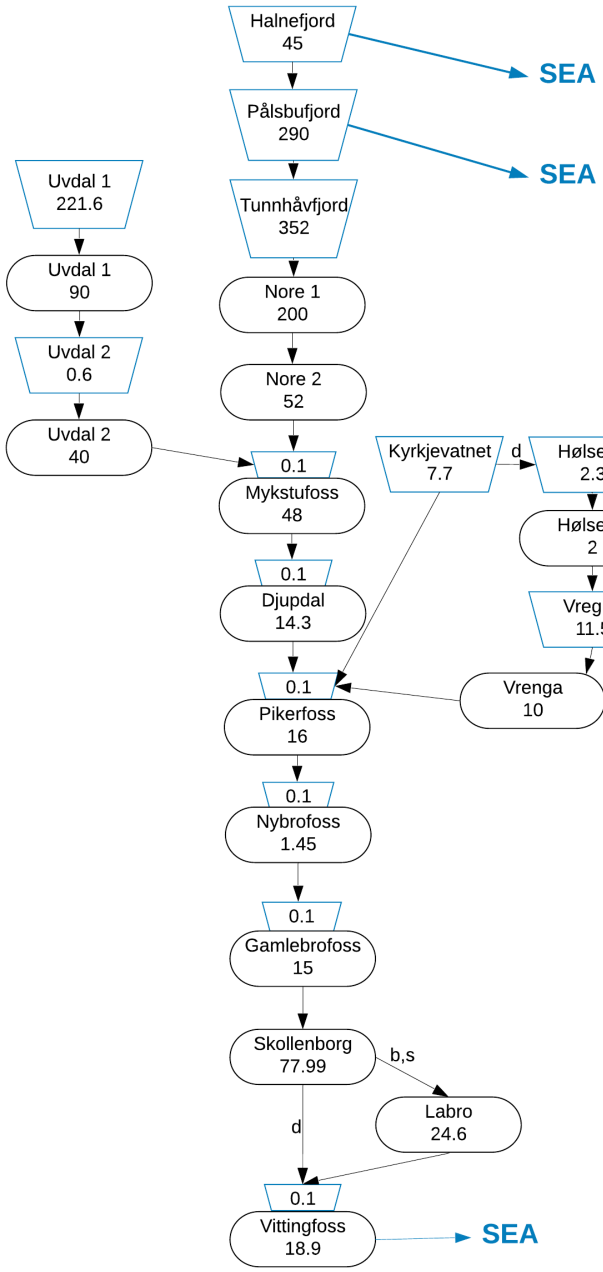


Figure 3.2: Structure of hydro system in Numedal

The structure of the hydro system in Numedal is quite simple, with bypass, spilling and discharge having the same discharge destination for most modules. However, this area has many cascaded power plants and reservoirs, which can lead to operational challenges. Especially where the stations only have minor intake reservoirs. If an upstream plant with higher capacity is running at full capacity, the downstream plant is bound to have significant spilling and bypass.

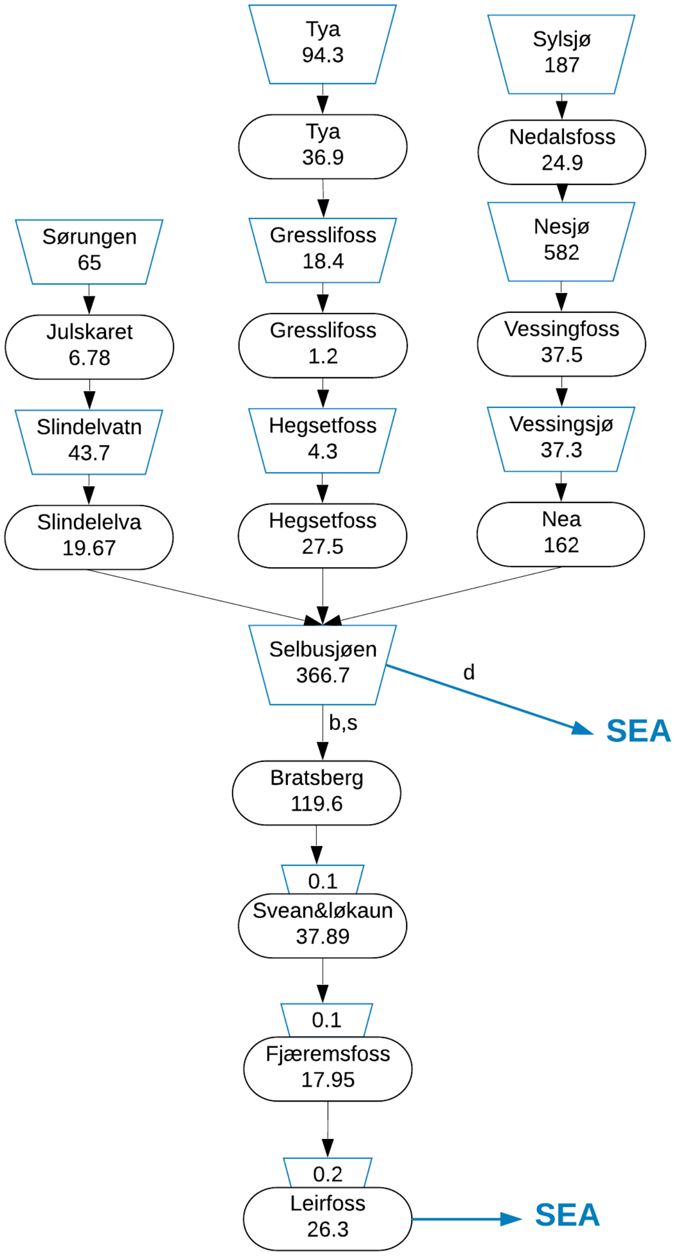


Figure 3.3: Structure of hydro system in TEV

The paths at TEV are quite simple, with all releases having the same termination point for most plants. The area has many large plants and reservoirs with significant storage capacity. The structure is quite simple, with the large reservoir at Selbusjøen being a central element as three river branches lead there. Upstream all plants have reservoirs of considerable sizes, which is ideal for scheduling. However, downstream the four plants have only small intake reservoirs and of varying sizes, which can complicate scheduling.

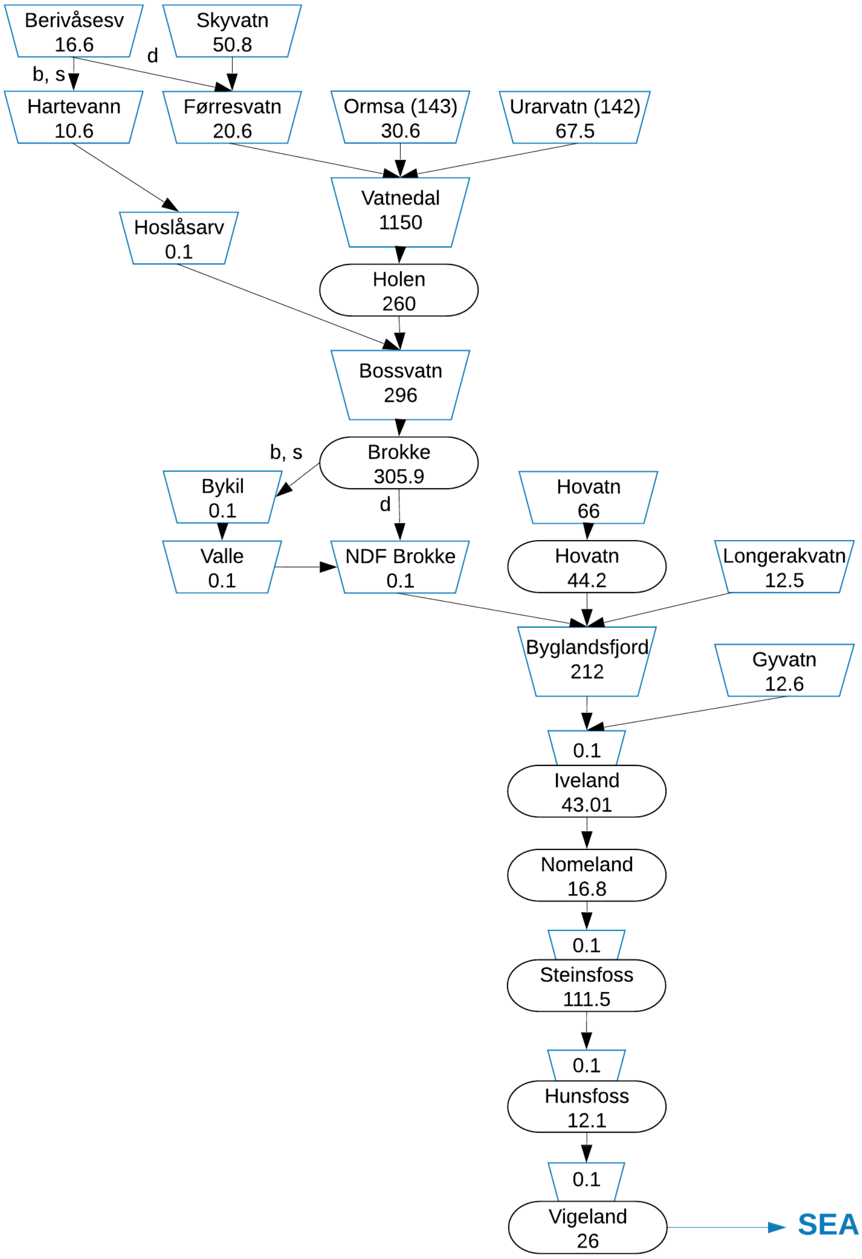


Figure 3.4: Structure of hydro system in Otra

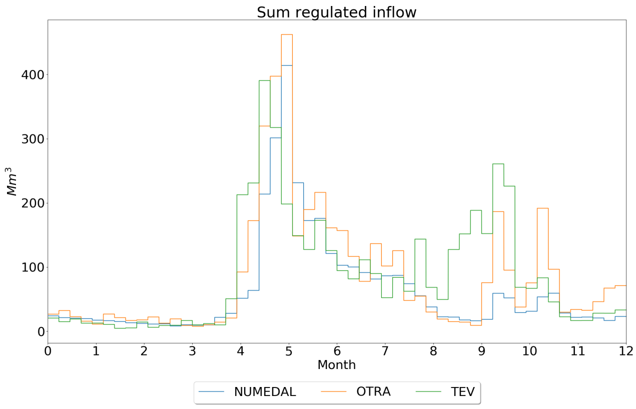
Otra has, at least regarding paths, the most complex hydro system of the three areas. Here, there are multiple places where several reservoirs and plants have the same destination. The system has some large reservoirs and plants. The river system ends in five cascaded plants with only small intake reservoirs, and small plants are followed by large and vice versa. These conditions make it difficult to determine the optimal schedule.

Inflow

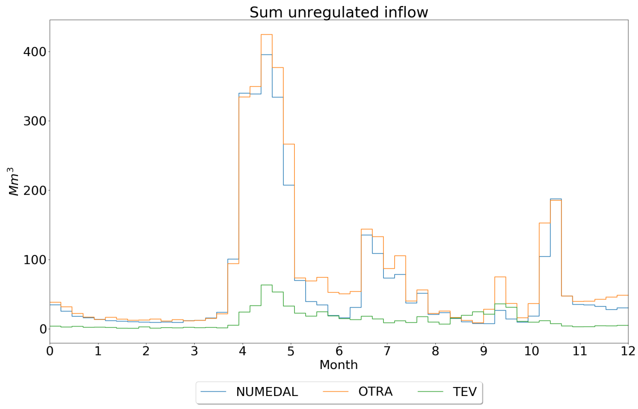
The yearly inflow per area is shown in Figure 3.5. The inflow input data has a daily resolution, for modeling purposes, the inflow has been assumed constant through the day.

As seen from Figure 3.5a regulated inflow in the three areas is similar throughout most of the year; apart from September-October when TEV has significantly higher inflow than the other areas, and two peaks in October and November when Otra has higher inflow. All areas have a definite seasonal component, with low inflow in the winter and high inflow in spring/early summer when the snow stores melt as well as in the autumn.

Figure 3.5b shows that Otra and Numedal have very similar levels of unregulated inflow throughout the whole year, TEV has a meager amount of unregulated inflow and only small changes between the seasons. Interestingly the amount of unregulated inflow is similar to regulated inflow for Numedal and Otra.



(a) Regulated inflow



(b) Unregulated inflow

Figure 3.5: First year inflow

3.2 Market

The market data includes flooding, rationing, and any thermal units in the area. Flooding refers to flooding the market with power and is represented by negative capacity. All areas have unlimited opportunity for flooding and rationing. Flooding is low cost or free, while rationing is very expensive. In reality, the cost of flooding is mostly covered by the loss of water (opportunity cost).

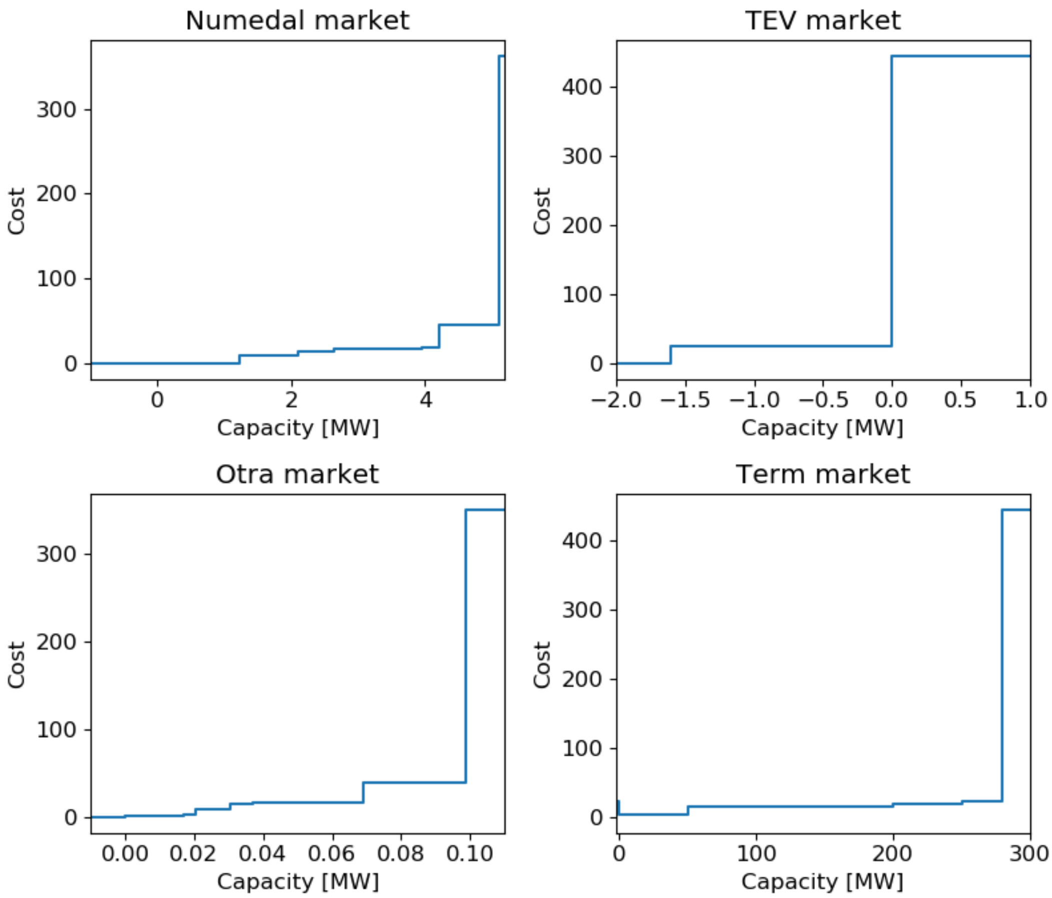


Figure 3.6: Market steps per area, first week

Observe that Numedal and Otra have minimal thermal capacities, each unit < 1.5MW. The market in TEV consists of only flooding and rationing, no thermal units. Term, which is a thermal area has, as expected, thermal capacities of considerable size.

Figure 3.6 only shows the market steps for the first week. There are some small variations in both capacity and cost throughout the weeks covered by the dataset. Additionally, due to an error in the dataset the second and third market steps in Term switch capacity and cost in week 105.

The thermal units in Term are summarized in Table 3.2.

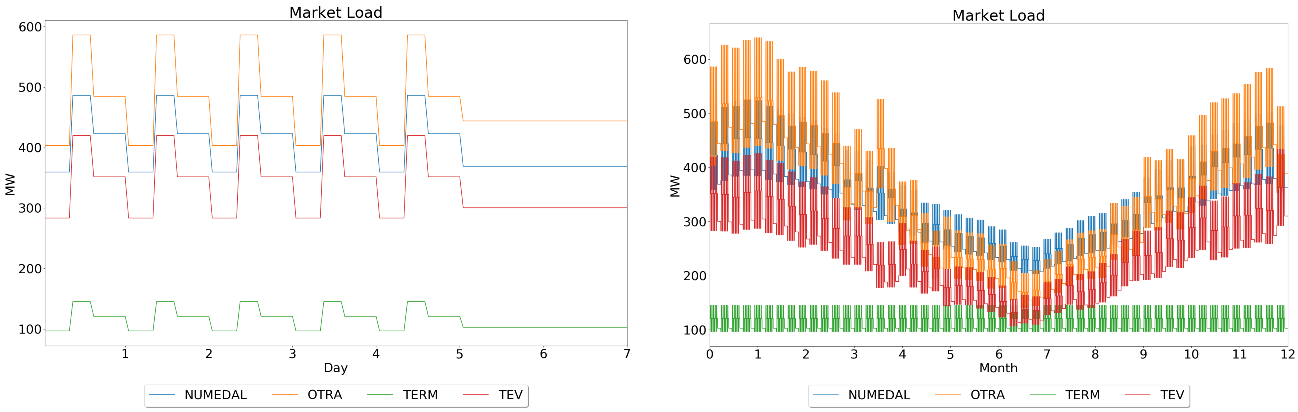
Table 3.2: Data on thermal units in Term

Plant	**Capacity, MW**	**Running cost, €$/MWh$**
G2	30	24
G3	30	24
G4	50	20
G5	150	15
G6	50	5

3.3 Demand

The system demand for the first week is as shown in Figure 3.7a. There is a clear repeating three-step pattern in all areas during the weekdays, where the peaks and valleys coincide across areas. The weekend has constant demand, somewhat higher than the weekday valleys. Demand is highest in Otra followed by TEV, Numedal and lastly Term.

The demand through the year is shown in Figure 3.7b, from which an evident seasonal variation can be observed for the Norwegian areas while Term has a constant profile and magnitude through the year. Numedal has a flatter demand than the other Norwegian areas and becomes the highest consuming area in the summer months.



(a) First week demand per area

(b) Year demand per area

Figure 3.7: Weekly and yearly demand in system

It is obvious that assuming the same load profile and magnitude for every weekday, as well as constant demand for weekends is a rough estimation of the actual demand. Besides, the consumption will in reality usually have a higher peak in the afternoon/evening than the morning peak.

3.4 Transmission

As shown in Figure 3.1, there are four lines in the *4del* system. Transmission capacities between areas, transmission losses, and cable types are shown in Table 3.3.

Table 3.3: Transmission capacity and losses

Areas	**Capacity, MW**	**Line loss, %**	**Type**
Numedal - TEV	200	2	AC
TEV - Otra	200	2	AC
Otra - Numedal	100	2	AC
Otra - Term	200	4	HVDC

3.5 Time resolution

It is essential to have time resolution appropriate for the model applications, meeting requirements for time steps. In the provided dataset the market and demand data have 17 time-steps per week, each of different lengths. Inflow has, as previously mentioned, daily resolution. Cuts are provided per week for each module.

Chapter 4 | Problem formulation

This chapter starts by covering some introductory background on optimization and deterministic and stochastic models. After that, the formulation of PriMod upon reception from SINTEF is presented, while developments contributed by the author are described and studied in Chapter 5. The formulation of the final version PriMod-NTNU is included in Appendix D.

4.1 Optimization

Optimization is a powerful tool that is used to determine the best alternative in decision-making situations. Models describing problems in technical or economic systems are formulated, with the goal of gaining insight into the system and finding the best possible solution to the problem. ”Best” indicates that an objective has been defined, and ”possible” indicates that there are restrictions constraining the solution [37]. Models describing real-life systems quickly become too large and too complex to be solved within a reasonable time by hand, and even by computers. For this reason developments in computer performance and optimization methods and algorithms have been essential to enabling their solution. In some cases, such as for hydro-thermal scheduling, the problem is decomposed to more manageable sub-problems, and different methods are applied to each [31].

4.2 Deterministic models

Deterministic models are models for which the start conditions, external parameters, and final conditions are assumed known. The task is to find the decisions within the problem period making the optimal path from the start- to the final conditions while adhering to the constraints. The start and final conditions can be provided by other deterministic or non-deterministic models, or be based on assumptions and heuristics.

In reality, in the majority of problems, there will be a number of parameters that introduce uncertainty to the system. Despite this, deterministic models are often used for decision support, because:

- Uncertainty can be difficult to model or quantify
- Variables may be correlated, complicating the uncertainty modeling
- The solution techniques become complicated when uncertainty is considered.
- Deterministic models are the only models that can be solved for the actual problem, with reasonable computation time.
- Generally, deterministic models are intuitive and easily interpretable
- Users like analysis of specific scenarios.

In order to compensate for uncertainty, it is possible to use scenario modeling with a deterministic model. This method is faster than solving stochastic models and provides near optimal results; it is therefore particularly useful for larger models [31].

4.3 Stochastic models

Uncertainties will always be present in any real-life problem, affecting the optimal solution. Neglecting uncertainties can lead to solutions that are not robust to changing conditions. Stochastic models are often applied when there is uncertainty in a system and expected values alone might not be sufficient. The models explicitly take into account the stochastic variables that may have several realizations at each stage. These realizations are often described by a probability distribution that is used to weight future data in the form of series of estimates [37].

The problem is split into stages, illustrated in Figure 4.1, where each stage has an associated set of possible outcomes weighted by probabilities. Decisions in each stage must be made before other information becomes available, the obtained results allow for the next stage decisions to be made. The objective result may not be as good as that from a deterministic model, but it is a more probable solution. Due to the multiple scenarios of each stage, stochastic models can become very large. Their strength is that they reduce risk, by providing a more robust solution [38].

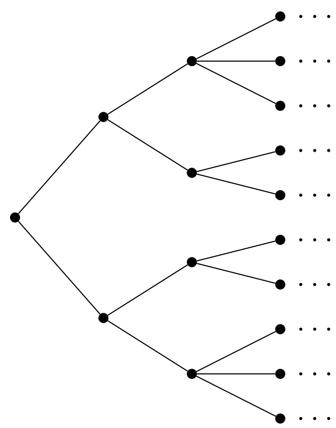


Figure 4.1: Scenario tree

4.4 Weekly hydro-thermal scheduling problem

In PriMod, the short-term hydro-thermal problem is solved in weekly increments with hourly resolution. The goal is to determine the optimal production plan for the system for the whole week, minimizing the cost. Though the problem, in reality, is stochastic, due to uncertainties in inflow, wind power production (WPP) and solar power production (SPP), the problem is formulated as its deterministic equivalent. Uncertainties in system price need not be considered as these are internal in the model. A deterministic approach is usually applied when there is a need for high level of detail in the system description, as a stochastic model will quickly become too large to solve efficiently. In the case of PriMod, the deterministic formulation has been used as a first approach in the model development; a future version may be stochastic if the software allows for it with reasonable computation time.

4.4.1 Nomenclature

In the following, superscripts are part of the name, while subscripts are indices. Parameters and sets are capitalized, while variables and indices are not. The description is on a system level. All parameters are defined at area level, for simplicity the index a is not included in parameters and variables. The formulation is somewhat simplified compared to the implementations itself, as some subsets are not necessary for the mathematical description of the model.

Indices

a	system area
k	time step
t	week
r	reservoir
j	unit, segment
c	cut
i	other area, other reservoir

Index sets

$\mathscr{A}$	set of price areas
$\mathscr{T}$	set of weeks
$\mathscr{K}_t$	set of time steps in week t
$\mathscr{C}_t$	set of Benders cuts for week t
$\mathscr{M}_a$	set of market steps in area a
$\mathscr{W}_a$	set of wind parks in area a
$\mathscr{R}_a$	set of reservoirs in area a
$\mathscr{R}_a^{reg}$	set of regulated reservoirs in area a
$\mathscr{R}_a^{ureg}$	set of unregulated reservoirs in area a
$\mathscr{R}_r^{up}$	set of upstream reservoirs with destination at reservoir r
$\mathscr{N}_r^{PQ}$	segments in piecewise-linear PQ-curve for reservoir r

Parameters

Tr_j^{loss}	transmission loss to area j, fraction (0,1)
M_{jk}^C	market price for market step j, (€/MWh)
L_k	aggregated load, (MW)
η_{rj}	generation efficiency per PQ-curve segment j, (MW/m^3/s)
H_r	relative head (h/h$_0$), refers to initial reservoir level, fraction (0,1)
Pum_r^{pow}	pumping power from reservoir, (MW/m^3/s)
$\mathcal{P}^S$	penalty for spillage, (€/m^3/s)
$\mathcal{P}^B$	penalty for bypass, (€/m^3/s)
$\mathcal{P}^{tank}$	penalty for tanking, (€/m^3/s)
I_{rk}^{reg}	regulated inflow to reservoir r, (Mm^3)
I_{rk}^{ureg}	unregulated inflow to reservoir r, (Mm^3)
W_k	wind production, (MWh)
β_c	Benders cut right-hand side for cut c, (10^3 €)
π_{rc}	Benders cut coefficient for reservoir r and cut c, (10^3 €/Mm^3)

Decision variables

tr_{jk}	transmission between areas i and j, (MW)
m_{jk}	purchase(+)/sales(-) from market step j, (MWh)
x_{rk}	reservoir level for r, (Mm^3)
q_{rk}	release form reservoir r, (m^3/s)
q_{rjk}^D	discharge through station r per segment j, (m^3/s)
q_{rk}^B	bypass from reservoir r, (m^3/s)
q_{rk}^S	spillage from reservoir r, (m^3/s)
q_{rk}^P	pumping at r, (m^3/s)
q_{rk}^T	tunnelling from reservoir r, (m^3/s)
α	future profit function, (10^3 €)
ph_{rk}	production from module/reservoir r, (MW)
$tank_r$	tanking for reservoir r, (m^3/s)

The goal of the hydro-thermal scheduling problem is to minimize the total cost of production, or dually to maximize the profit of production, in the whole system within the optimization period. Thus, the objective is formulated as:

minimize

$$\pi = \sum_{a\in\mathscr{A}} \left(\sum_{k\in\mathscr{K}} \left(\sum_{j\in\mathscr{M}_a} M_j^{cost} m_{jk} + \sum_{r\in\mathscr{R}_a} (P^S q_{rk}^S + P^B q_{rk}^B) \right) + \sum_{r\in\mathscr{R}_a} P^{tank} tank_r \right) + \alpha \quad (4.1)$$

, for each time step, revenue or cost of production is calculated from the sales and purchases to the market. The cost of bypass and spilling is added. Tanking is included for the first time period to avoid infeasible solutions. The last term is the future profit function, which expresses the expected future profit for the system.

subject to $\forall a, t, k, r \in \mathscr{A}, \mathscr{T}, \mathscr{K}_t, \mathscr{R}_a$

reservoir balance:

$$x_{rk} - x_{rk-1} + q_{rk} + q_{rk}^S + q_{rk}^P + q_{rk}^T - \sum_{i\in\mathscr{R}_r^{up}} (q_{ik} + q_{ik}^S + q_{ik}^P + q_{ik}^T) = I_{rk}^{reg} \quad (4.2)$$

, which states that the difference in reservoir level from one week to the next plus water removed from the reservoir through release, spilling, pumping and tunnelling has to be equal to the regular storable inflow as well as the of sum storable inflow from release, spilling, pumping and tunnelling originating from upstream reservoirs that lead to the indexed reservoir.

release balance:

$$\sum_{j\in\mathscr{N}_r^{PQ}} q_{rjk}^D + q_{rk}^B - q_{rk} = I_{rk}^{ureg} \quad (4.3)$$

, stating that water that is discharged (sum over segments) or bypassed at a station but can not be covered by the release from the reservoir must equal the unregulated inflow.

power balance:

$$\sum_{r\in\mathscr{R}_a}\Big(\sum_{j\in\mathscr{N}_r^{PQ}} H_r\eta_{rj}q^D_{rjk} - Pum_r^{pow}q^P_{rk}\Big) + \sum_{j\in\mathscr{A}}\Big(tr_{to,jk}(1-Tr_j^{loss}) - tr_{from,jk}\Big) + \sum_{j\in\mathscr{M}_a} m_{jk} = L_k - W_k \quad (4.4)$$

applies to areas with hydro production. The equation states that hydro production plus market sales/purchases minus transmission from area and pumping power in area, plus transmission to the area equals aggregated load minus wind production. Wind, as an uncontrollable production, is modelled as a reduction in demand. For purely thermal areas the first summation term falls out by summing to zero, while for purely hydro areas the third term sums to zero.

Benders cut constraining expected future cost:

$$\alpha - \sum_{a\in\mathscr{A}}\sum_{c\in\mathscr{C}_t}\sum_{r\in\mathscr{R}_a^{reg}} \pi_{rc}x_{rk} \geq \sum_{c\in\mathscr{C}_t}\beta_c \quad (4.5)$$

In addition to these there are max-min constraints for the decision variables. The limits for reservoir level, bypass and discharge, are implemented as soft constraints to avoid infeasibility.

Hence, the system can be defined by the objective function and only five constraints, not considering variable limitations and constraints implemented only to ensure feasibility.

Hydro generation is a post processing variable calculated by Eq. (4.6) after the system is solved.

$$ph_{rk} = \sum_{j\in\mathscr{N}_r^{PQ}} H_r\mu_{rj}q^D_{rjk} \quad (4.6)$$

Chapter 5 | Case studies

5.1 Case 1: Base-case

For the base-case, the methodology covers basic changes that were implemented to be used in all cases, and that were necessary for the constraint implementations. The obtained results are based on the *4del* dataset, with minor changes as described in the methodology section, the changes are mainly structural. The discussion section focuses on irregular data and necessary changes that should be implemented in the following cases to avoid odd results.

5.1.1 Methodology

As described in Section 3.5, the week is divided into 17 steps in the original *4del* dataset. In order to implement ramping constraints and start/stop on units, it was necessary to change to an hourly resolution of 168 time-steps per week as these constraints are enforced per hour in a real system. Consequently, any data with incorrect resolution was stretched to obtain an hourly resolution. This process was enforced upon demand, market data, and inflow. Basic assumptions of constant load, cost and inflow were used for easy implementation.

Additionally, to allow for simple handling of thermal units, the market variable was dissolved to a market flooding variable (f_{ak}), thermal units, and a load rationing (r_{ak}) for each area. The cost of flooding, F^C, was set to €0.01/MWh, similar to the dataset, while the cost of rationing, R^C, was set to €3000/MWh to reflect the current cost in NordPool. The thermal plants are then in the set $\mathscr{P}_a$ while the unit, j, production is then in the variable t_{jk} at the cost of T_j^C with max production T_j^{cap}.

$\mathscr{P}_a$	set of thermal plants in area a
F^C	cost of market flooding, (€/MWh)
R^C	cost of load curtailment, (€/MWh)
T_j^C	running cost of unit j, (€/MWh)
T_j^{cap}	maximum production from unit j, (MW)
f_{ak}	market flooding in area a in time period k, (MW)
r_{ak}	load curtailment in area a in time period k, (MW)

The objective function of Eq. (4.1) is then updated to Eq. (5.1)

$$\pi = \sum_{a\in\mathscr{A}} \left(\sum_{k\in\mathscr{K}} \left(F^C f_{ak} + R^C r_{ak} \sum_{j\in\mathscr{P}_a} T_j^C t_{jk} + \sum_{r\in\mathscr{R}_a} (\mathcal{P}^S q_{rk}^S + \mathcal{P}^B q_{rk}^B) \right) + \sum_{r\in\mathscr{R}_a} \mathcal{P}^T tank_{ir} \right) + \alpha \quad (5.1)$$

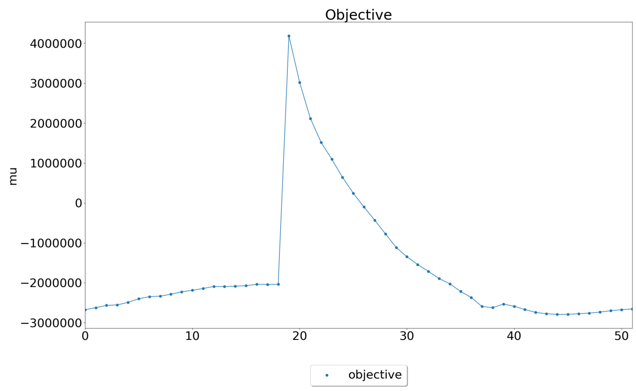
and the power balance constraint of Eq. (4.4) is updated to Eq. (5.2)

$$\sum_{r\in\mathscr{R}_a} \Big(\sum_{j\in\mathscr{N}_r^{PQ}} H_r \eta_{rj} q_{rjk}^D - Pum_r^{pow} q_{rk}^P \Big) + \sum_{j\in\mathscr{A}} \Big(tr_{to,jk}(1 - Tr_j^{loss}) - tr_{from,jk} \Big) + F^C f_{ak} + R^C r_{ak} \sum_{j\in\mathscr{P}_a} T_j^C t_{jk} = L_k - W_k \quad (5.2)$$

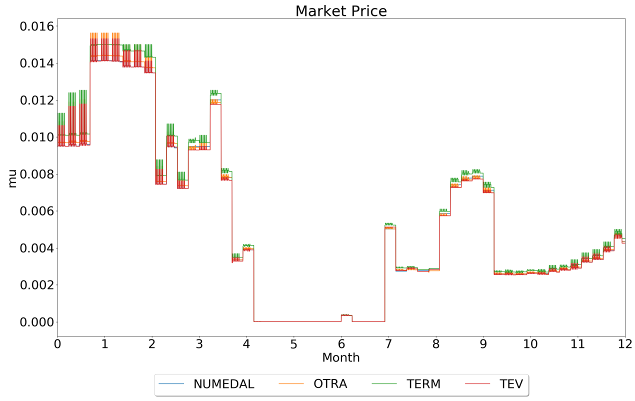
Thus, base-case results are obtained from optimization with data as described in Chapter 3 and adjustments as above. The results were used to become familiar with the model and system, as well as to identify changes that should be implemented for the other cases.

5.1.2 Results

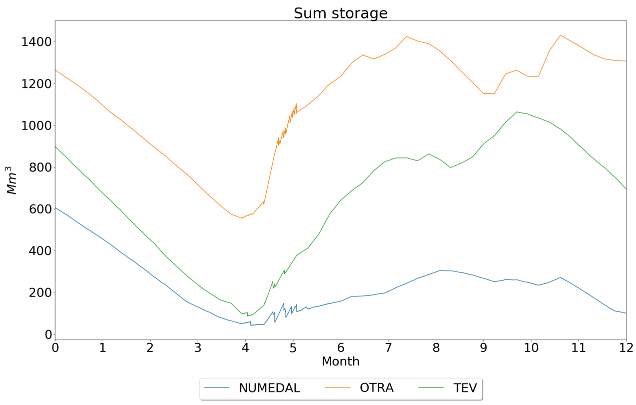
Figure 5.1 shows some key results for the *4del* system. The objective is shown in 5.1a, from this it can be seen that the system has a sudden spike in week 18, causing the system to become unprofitable. Figure 5.1b shows a clear season dependency on the market price, with high prices in the winter and low in the summer months. Also, note that the prices are close to equal for all areas, but somewhat higher in Term most of the year. There is an apparent price variation at the beginning of the year, but no significant price peaks. Figure 5.1c shows that the storage is emptied gradually until the introduction of lower reservoir bounds. Note also that the storage in Numedal is meager at the end of the year, while the other two areas have about the same volume as in the start. Finally, Figure 5.1d shows the duration curve for the sum of hydro production per area.



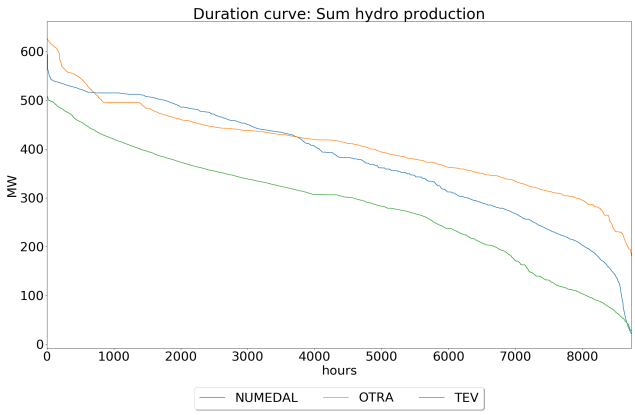
(a) Objective per week



(b) Market price per area



(c) Storage in hydro reservoirs

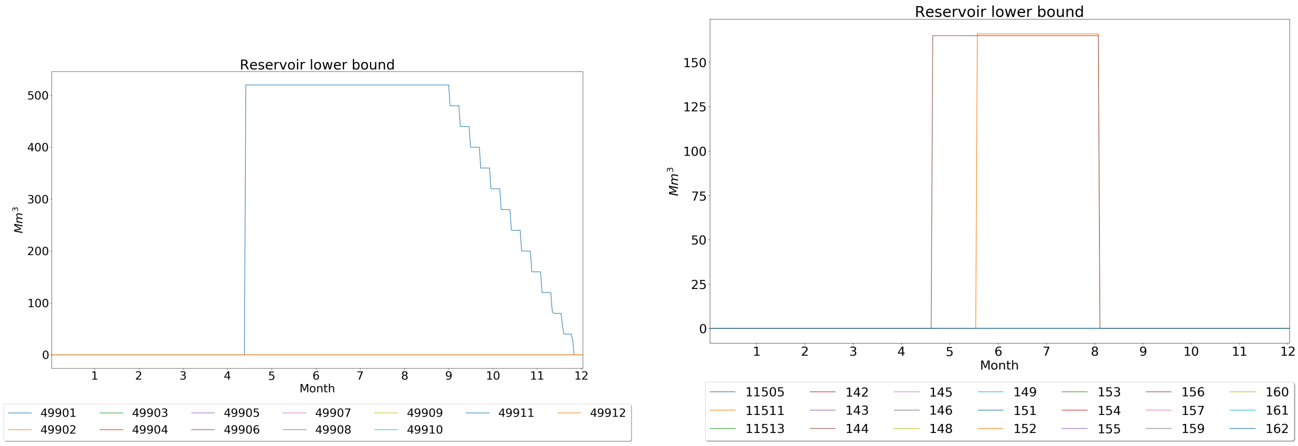


(d) Sum hydro production

Figure 5.1: Key result figures for base-case

5.1.3 Discussion

The spike in the objective, shown in Figure 5.1a was found to be caused by a reservoir penalty. The penalty occurs in TEV as well as Otra, when lower bounds are suddenly introduced for some of the reservoirs, shown in Figure 5.2. These reservoir constraints are expected to be reflected in the cuts to avoid the resulting bypass and discharge at upstream reservoirs. These results may indicate that the cuts are not correctly calibrated for the system. If they were, they should have signaled for the system to start storing water earlier in preparation for the storing season. Acquiring new cuts would require a rerun of the long-term and seasonal models on the SINTEF side and has been deemed unimportant for the development of this masterwork, as the system is only used for development and testing. Upon closer inspection of the results, it was found that these lower constraints are likely causing upstream reservoirs to have high discharge (causing market flooding) and bypass, to supply the water needed in the reservoirs.



(a) TEV (b) Otra

Figure 5.2: Lower reservoir bounds for TEV and Otra

Due to the huge share of hydro generation in Norway, the electricity prices are strongly dependent on water values. High prices in winter are expected as demand is high, particularly in Norway due to substantial use of electric heating, while inflow and storage are low. The prices decrease as the demand lowers and the snow stores melt and the rain sets in. Close to equal prices for all areas indicate sufficient transmission capacity to almost allow for free flow of power. No significant peak suggest that there are no significant bottlenecks in the system. The goal of interconnecting areas is to even out the prices and increasing the social welfare. Variation in the price in TEV at the beginning of the year may suggest the need for importing power from continental Europe. For most of the year, the hydro system is exporting power, indicated by the somewhat higher prices in Term.

The storage is expected to be depleted in the early months as the demand must be covered and there is minimal inflow to the system. Storing water in the low demand, high inflow summer months is crucial to secure sufficient power supply for the following winter season. The dis-proportionality between inflow and demand is one of the major challenges of hydro scheduling.

The low storage level in Numedal is likely to cause power shortages in the following time period and may indicate poor cuts for this area at the end of the year, or merely a lack of inflow. When running the optimization for two years, the reservoirs in Numedal and TEV are completely depleted in the spring of the second year, see Figure 5.3, and water values are in the order of 1e7 in the first week of the second year.

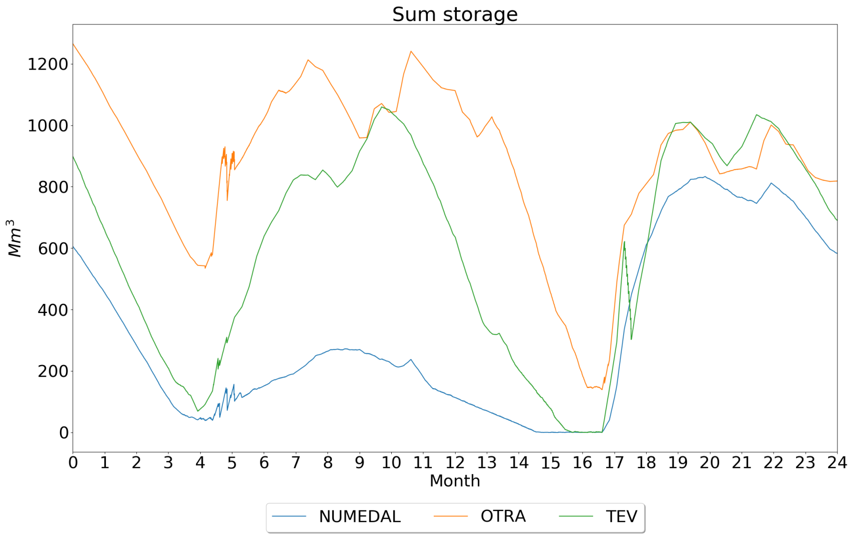


Figure 5.3: Hydro storage over two-year period

The duration curve shows that Numedal and TEV are close to producing at max capacity for a few hours of the year, while Otra has about 25% of its generation capacity unused. All areas have considerable production throughout most of the year.

5.2 Case 2: Benchmark

Due to the quite stable nature of the base-case, this case was developed for benchmarking. The goal was to create a system with more variability that would yield interesting results in the studies.

5.2.1 Methodology

The reservoir constraints discussed in Section 5.1.3 were removed to avoid penalties.

More importantly, wind generation was introduced into the system. For the Norwegian system, information about installed capacity with the location was retrieved from an open-source data download resource provided by NVE[1](Downloaded May 28th 2018) [39]. For the thermal area, wind capacity of Latvia was used as it had suitable capacity considering the load in Term and is part of the Baltic region in NordPool. Data on national aggregated generation capacity for European countries was retrieved from OPSD, which is an open-source resource for power system data for European countries provided by the Technical University of Berlin[2](Downloaded May 28th 2018) [40].

Capacity factors for onshore wind were retrieved from the EMHIRES datasets from SETIS, which are also open-source[3](Downloaded May 28th 2018) [41]. For simplicity, wind capacity factors were assumed to be equal for all the Norwegian areas.

For the studies in this thesis, the wind generation is assumed known, thereby keeping the model deterministic. Thus, the wind generation could be considered a reduction of load and simply be subtracted from the load for implementation.

When increasing the generation capacity, it was necessary also to increase the load to maintain the ratio between generation and demand, which is a requirement to ensure the validity of the cuts. The load was increased relative to the installed wind generation (average CF 0.23) and the average load through the year, using:

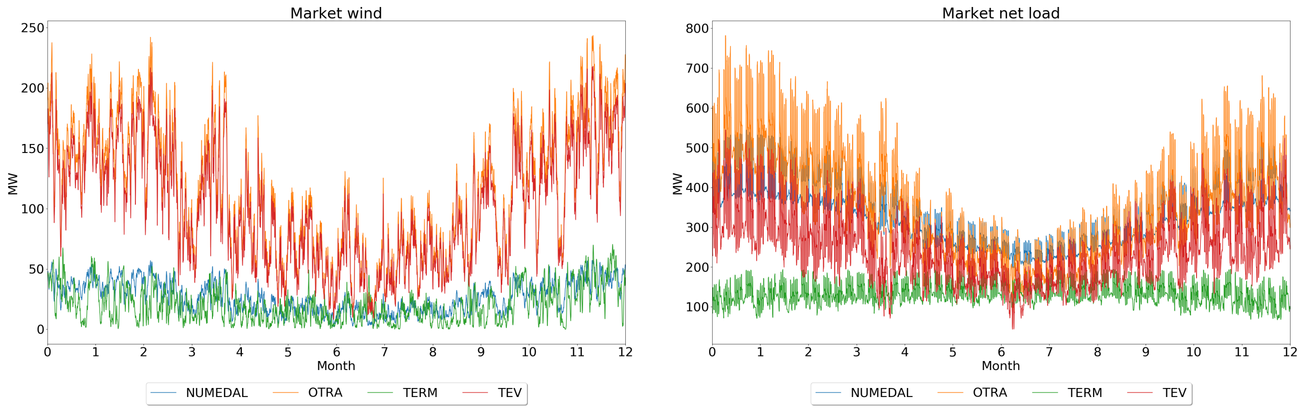
$$L_{ak} = (1 + 0.25 W_a^{cap} / L_a^{avg}) L_{ak}$$

[1]Distributed under the Norwegian Licence for Open Government Data (NLOD).
[2]Distributed as an Attribution 4.0 International creative common
[3]Distributed under the European Commission reuse and copyright notice.

5.2.2 Results

Since this case is to be used for benchmarking, many results will be relevant for the study of later cases. Therefore, additional results that are not directly relevant for now, but will be useful later, are included in Appendix B.1.

The wind production for the year is shown in Figure 5.4a, while Figure 5.4b shows the resulting net load for the system. Comparing the net load to the base-case load shown in Figure 3.7b, it can be seen that the load variation has increased significantly.

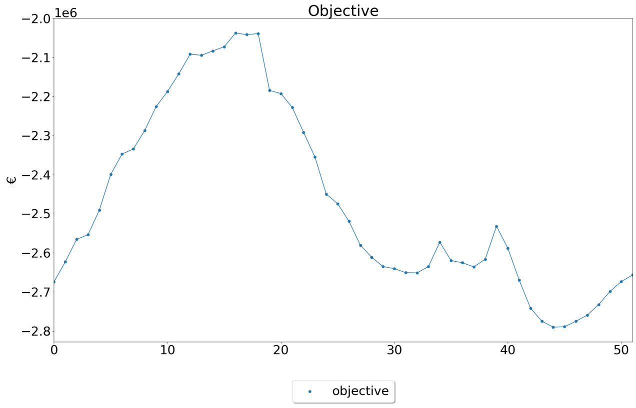


(a) Wind production per area for one year

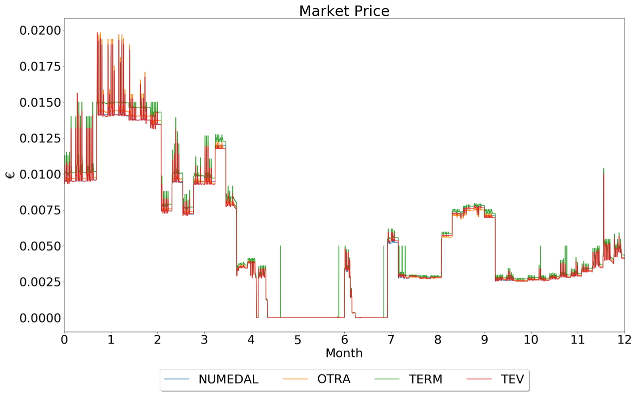
(b) Net load in the system for one year

Figure 5.4: Wind production and system net load in benchmark case

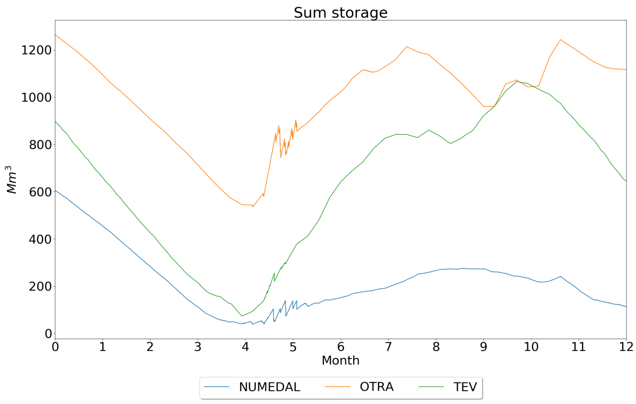
Figure 5.5 shows the same key results as were presented for the base-case. Looking at Figure 5.5a the objective no longer has an extreme peak from the 18$^{\text{th}}$ week. Considering the storage levels, Figure 5.5c shows practically no change; TEV peaks somewhat higher than before and Numedal has somewhat higher storage levels in months 7-10, but the profiles are unchanged and have the same end reservoir level as for the base-case. The market price in Figure 5.5b shows a significant increase in variability, especially in the early months, while the profile and base levels remain mostly the same. There are several cases of significantly higher prices in Term during the summer months. While the utilization of hydro generation in TEV and Numedal show minimal change, Figure 5.5d shows a considerable change in peak production in Otra. For this case, Otra is closing in on peak production for some hours in the year and has somewhat higher baseload than before.



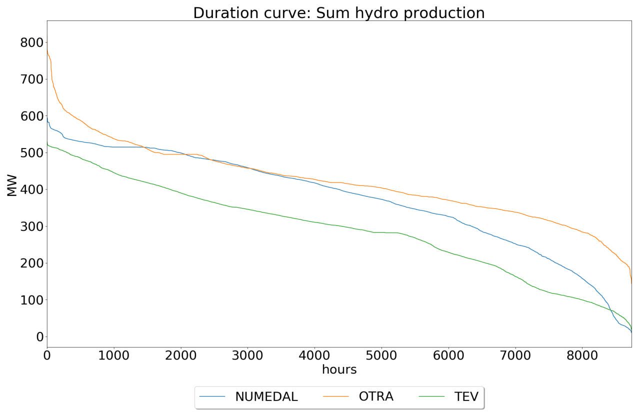
(a) Objective per week



(b) Market price per area



(c) Storage in hydro reservoirs



(d) Sum hydro production

Figure 5.5: Key result figures for benchmark case

5.2.3 Discussion

The removal of lower reservoir constraints seems to have had minimal if any effect on the system schedule and dispatch as the storage level has not changed significantly from the base-case, indicating that the storage requirement is sufficiently represented in the cuts. Considering the generation discharge, bypass, and flooding in Otra and TEV, there is no significant change in the months where the lower bounds were enforced.

The introduction of wind into the system has had the desired effect of increasing variability as this is readily observed in both net load and market price. The seemingly unchanged base levels for the market price may indicate that the load increase was suitable relative to the introduced wind generation. Hours with significant price differences indicate bottlenecks in the transmission system. The increase in hydro generation in Otra occurs as the hydro reservoirs are used to balance the variable wind generation.

5.3 Case 3: Ramping

This case considers one of the main contributions of this thesis; the implementation of ramping constraints. First, the method used for implementing the constraint is presented. Then the case studies are developed with values based on realistic values presented in Section 2.3.5. Then follows a presentation of relevant results, and finally a discussion of these.

5.3.1 Methodology

As covered in Section 2.3.5, ramping constraints are enforced only on HVDC lines as these flows are controllable. In the *4del* system only the line from Otra to Term is HVDC. Though the change in flow, in reality, happens over a 20 minute period, it is implemented in the model as if instantaneous for the sake of convenience.

To enforce the ramping constraint, a new parameter expressing the limitation on ramping between two areas, Tr_{ij}^{ramp}, is introduced. For the purpose of this work, the parameter is implemented as a fixed limit, but it might just as well be time dependent.

The ramping constraint is expressed as

$$-Tr_{ij}^{ramp} \leq E_{ijk} - E_{ijk-1} \leq Tr_{ij}^{ramp} \tag{5.3}$$

, where E_{ijk} is the power exchange, or net transmission.

A typical implementation would be to define transmission with $tr_{ij} = -tr_{ji}$, so tr could directly replace E in Eq. (5.3). However, in PriMod, tr_{ij} is limited to take positive values and is in no way constrained or defined in relation to tr_{ji}. tr_{ij} is in fact injected power at node i towards node j. The power exchange is then determines as $tr_{ijk} - tr_{jik}(1 - Tr_{ij}^{loss})$, and the transmission constraint is implemented as in Eq. (5.4).

$$-Tr_{ij}^{ramp} \leq (tr_{ijk} - tr_{jik}(1 - Tr_{ij}^{loss})) - (tr_{ijk-1} - tr_{jik-1}(1 - Tr_{ij}^{loss})) \leq Tr_{ij}^{ramp} \tag{5.4}$$

The system has been studied with the current intercountry transmission capacity of

200MW, and case with additional transmission capacity from TEV to Term of 233MW, with 4 % loss as the other HVDC line, which equals the relative increase the system will see with the NL and NSL cables by 2021. For the studies, the value of the ramping limit, Tr_{ij}^{ramp}, was decided based on current and possible future relative ramping limits as presented in Table 2.3. From this, the ramping limits for 200MW and 233MW lines were calculated resulting in Table 5.1

Table 5.1: Relative ramping limits

	Ramping limit, MW/h	
%	**200MW line**	**233MW line**
28.57	57.14	66.57
42.86	85.72	99.86
57.14	114.28	133.14
85.71	171.42	199.70
171.43	342.86	399.43

Based on the ramping results for the benchmarking case, Figure B.1, only the two strictest limits would enforce any noticeable change in the system solution with a single line. For the case with two HVDC lines, a case with no ramping constraint is run for benchmarking, and the lower three limits are used for analyzes.

In an attempt to obtain exciting results, the cases were run for weeks 36-40 when ramping was found to have the most considerable effect on the system results.

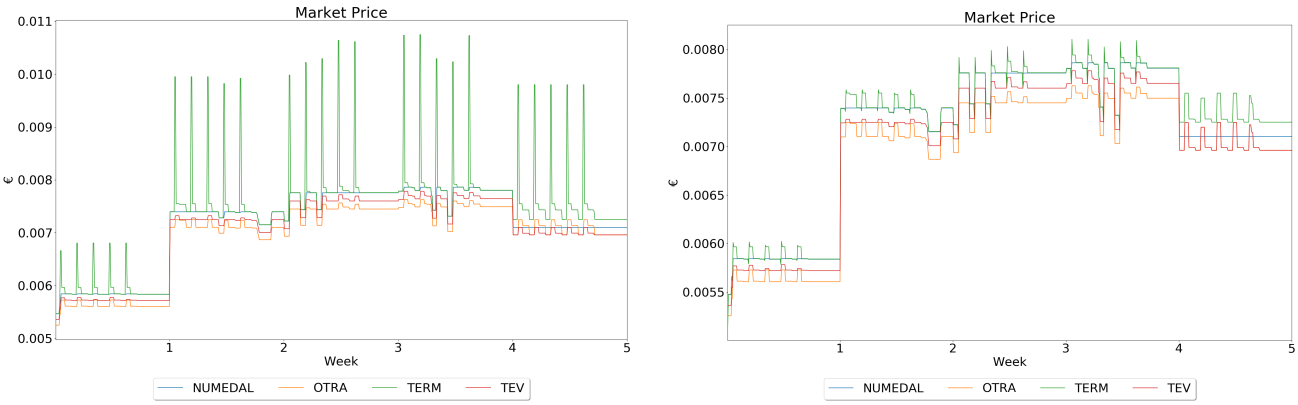
5.3.2 Results

To analyze the effect of ramping the results from seven cases with realistic ramping rates are presented; 1 line with none, 43 % and 29 % ramping, and 2 lines with none, 57 %, 43 % and 29 % ramping.

For the considered ramping rates, the system is only visibly affected by ramping at 28.6 %. The prices, shown in Figure 5.6 can be seen to spike in the early hours of each day.

For the other cases, the difference is not visually observable but is reflected in the objective value. A summary of the results from all cases is presented in Table 5.2. Note that as

[4]A suspected bug that occurs in the market price evaluation under strict ramping constraints was discovered. The data has been modified for this plot; the original is presented in Figure B.3 of the results Appendix B.3. The same behavior is observed for some hours in the benchmarking market price.



(a) One line with 28.6 % ramping[4] (b) Two lines with 28.6 % ramping

Figure 5.6: Market price in weeks 36-40, with 28.6 % ramping constraint

the problem is defined as a minimization problem - consequently, a positive change in the objective value indicates a less optimal solution.

Table 5.2: Change in objective value relative to benchmarking case

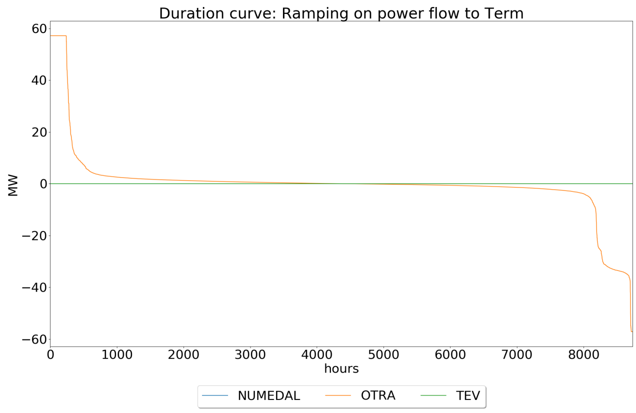
		Change in objective value, €					
Week	**Benchmark**	**1l 43%**	**1l 29%**	**2l none**	**2l 57%**	**2l 43%**	**2l 29%**
36	-2,619,704	1204	2754	430	1499	3351	2193
37	-2,625,511	425	949	146	480	1133	737
38	-2,635,861	237	514	73	230	594	381
39	-2,616,611	978	2224	336	1178	2682	1749
40	-2,531,851	10	-5	-7	-56	-42	-34
Year sum	-128,641,039	3081	6400	1450	3125	7966	5258

Note: 1l is used for the cases with 1 HVDC line, similarly 2l for cases with 2 lines

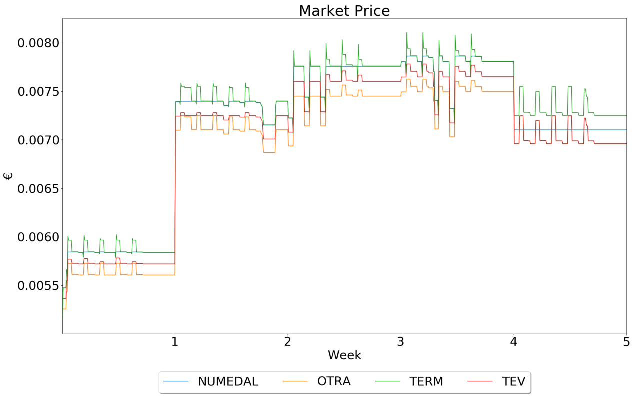
Considering the duration curves, it can be seen that ramping is constraining in the system for very few hours of the year. Apart from in the cases with 28.6 % ramping when maximum ramping is utilized 300h in a year (3.4 %) as can be seen from Figure 5.7. For the case with two HVDC lines, it is not known whether the constraining periods for each line coincide.

5.3.3 Discussion

The difference in results between cases is difficult to spot as the system will simply require an extra hour to reach the desired transmission level. However, for the lowest ramping case the ramping constriction becomes significant enough to require a longer time to



(a) System with one line



(b) System with two lines

Figure 5.7: Ramping duration curve, with 28.6 % ramping

reach the optimal transmission level, thereby causing a bottleneck and a significant price difference between areas.

Price spikes occur in the early hour of each day as the demand goes from low night levels to the highest daily consumption in the morning peak hours. A slight price difference between the areas can also be observed, indicating a limitation in the supply of hydropower or transmission capacity. For the one line system, the effect of the ramping constraint becomes evident at 33.8 % ramping, or 67.6MW ramping capacity. On real lines with 700MW and 1400MW capacity, this would equal 236.6MW and 473.2MW. Similarly, for the two line system, the ramping constraint first becomes significant at 15.6 % of line capacity, which is 31.2MW for the 200MW line and 36.35MW for the 233MW line (in total 67.6MW). On real cables with 700MW and 1400MW capacity, this would equal 109.2MW and 218.4MW respectively.

Considering the objective values in Table 5.2, for all weeks apart from 40, the solution is less optimal for all considered ramping cases. However, concluding from these results should be done carefully; these results are an excerpt from a run optimizing for the whole year. Hence, the weekly initial values for reservoir levels and transmission level are different between the cases. This is likely to be the reason why most cases can obtain a slightly better solution for week 40.

5.4 Case 4: Start/stop

This chapter concerns the implementation and study of start/stop costs on thermal units, the second main contribution of this thesis. Two methods for implementation, weekly and receding MILP, are outlined and studied. Solver performance is a key consideration when evaluating the two methods.

The author equates the terms thermal *plant* and *unit*, though a thermal plant will typically contain several units.

5.4.1 Methodology

The consideration of startup and shutdown costs is crucial to obtaining a thermal production pattern that covers the costs of operation. It was decided that the costs would be implemented only for units of considerable size; >10 MW, since smaller units would not be able to cover the costs within a reasonable time. The introduction of these costs transforms the problem from LP to MILP, as binary variables are used to indicate the running state of the thermal plants. By limiting the cost to large units, the system will experience more realistic hydrothermal dynamics, without unnecessarily complicating the system with too many binary variables.

For this thesis it was decided to implement the MILP formulation in two ways; regular with solving MILP for one week at a time (Section 5.4.2), and using a receding horizon formulation that optimizes for the week in iterations (Section 5.4.3). The receding horizon is implemented with the expectation of faster solving time as each iteration will only have 24 binary variables per thermal unit, compared to 168 with a weekly MILP.

The optimization problem formulation is the same for the two implementation methods; the difference is purely structural within the model. Therefore, the following applies for both methods.

The thermal units have been separated from the market variable as described in Section 5.1.1. They are also given unique ID's so that all parameters can easily be linked to the correct unit. The thermal system can then be described through the sets, variables, and parameters in the table below.

$\mathscr{P}_a$	set of thermal plants in area a
C_j^{start}	startup cost of unit j, (€)
C_j^{stop}	shutdown cost of unit j, (€)
T_j^C	running cost of thermal unit j, (€/MWh)
T^{cap}	capacity of thermal unit j, (MW)
T_j^{min}	minimum load of unit j when running, (MW)
u_{jk}	unit j running, binary
v_{jk}^+	unit j started, $\in [0,1]$
v_{jk}^-	unit j stopped, $\in [0,1]$
t_{jk}	production from unit j, (MW)

The variables v_{jk}^+ and v_{jk}^- can be defined as continuous within [0,1] as long as they are constrained to take on the boundary values of 0 and 1. This is achieved through the constraint in Eq. (5.5), and is a valuable approach as it considerably shortens the computational time by limiting the number of binary variables in the problem.

$$v_{jk}^+ - v_{jk}^- = u_{jk} - u_{jk-1} \tag{5.5}$$

Subject to Eq. 5.5, the plant can be in the state combinations shown in Table 5.3.

Table 5.3: Possible unit states

v_{jk}^+	v_{jk}^-	u_{jk}	u_{jk-1}
0	0	0	0
1	0	1	0
0	1	0	1
0	0	1	1

With the new sets, variables, and parameters as defined above, the optimization problem has been updated to reflect the changes. The objective function in Eq. (5.1) is updated to Eq. (5.6), to include the startup and shutdown costs.

$$\pi = \sum_{a\in\mathscr{A}} \left(\sum_{k\in\mathscr{K}} \left(F^C f_{ak} + R^C r_{ak} + \sum_{j\in\mathscr{P}_a} T_j^C t_{jk} + \sum_{r\in\mathscr{R}_a} (\mathcal{P}^S q_{rk}^S + \mathcal{P}^B q_{rk}^B) \right.\right.$$
$$\left.\left. + \sum_{i\in\mathscr{T}_a} (C_i^{start} v_{ik}^+ + C_i^{stop} v_{ik}^-) \right) + \sum_{r\in\mathscr{R}_a} \mathcal{P}^T tank_{ir} \right) + \alpha \tag{5.6}$$

In order to ensure stable operation and minimize damage, thermal units should be run above minimum load, T_j^{min}. This limit is defined by the manufacturer and depends on the unit type. The thermal production limitation must then be modified to be enforced only if the unit is running.

$$T_j^{min} u_{jk} \leq t_{jk} \leq T_j^{cap} u_{jk} \tag{5.7}$$

5.4.2 Weekly MILP

The easiest way to implement the startup and shutdown costs is to define the whole week as a MILP problem, where a decision on the plant state is made for every hour in the week. One binary variable is then created for each thermal unit per hour in the week, giving 168 binary variables per plant. For longer time horizons, the problem is, as before, solved in weekly iterations.

5.4.3 Receding horizon MILP

With the aim of reducing computational time, the receding horizon structure is implemented. The weekly scheduling problem is then solved with daily iterations, with a shrinking time period. The method is illustrated in Figure 5.8. When solving from time period *t*, the first 24 hours of are formulated as the MILP problem where commitment decisions are made, while the remainder of the week is solved with LP problem. When moving to the next iteration *t+1*, the 24 hours that have been solved in detail are removed from the problem, while the results for the integer variables are used as input to the period. This continues until the end of the optimization period is reached, as the end horizon does not move. Thereby, the problem is solved in iterations with shrinking problem size, where the first 24 hours are a MILP problem, while the remainder of the week is an LP problem. With this implementation, each thermal plant will only have 24 binary variables to be decided per iteration, but seven iterations must be completed to solve for the whole week.

A set $\mathscr{K}_t^{MILP} \subset \mathscr{K}_t$ is defined to hold of the hours where thermal costs and constraints are enforced. $\mathscr{K}_t^{MILP}$ will be the first 24 hours of each iteration, and for the final iteration $\mathscr{K}_t^{MILP} \subseteq \mathscr{K}_t$

The two implementations have been studied with data from the Twenties project, as

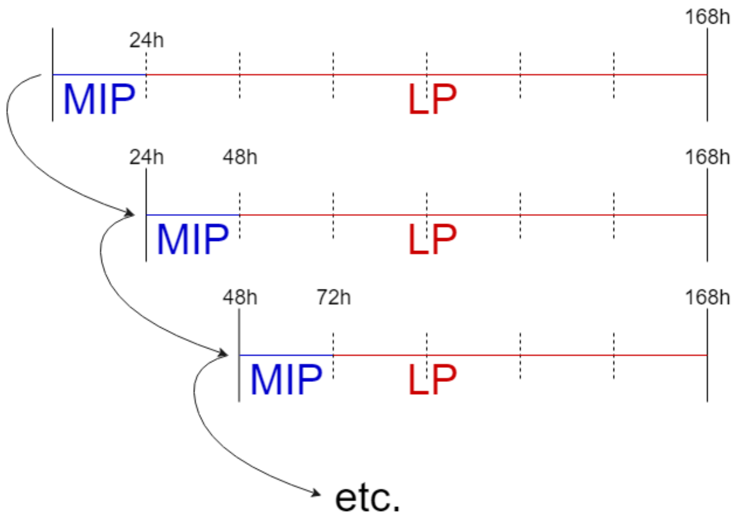


Figure 5.8: Illustration of receding horizon

summarized in Table 2.2. All units of considerable size, < 10MW, are found in Term (see Table 3.2). As there are five units in the *4del* dataset, it was decided that there should be one of each type; oil, gas, hard coal, lignite, nuclear. The types are distributed based on the plant size and running cost, and the corresponding costs and minimal load are taken from the Twenties data. This results in Term having a thermal system as described in Table 5.4

Table 5.4: Initial data on thermal units in Term

Unit info				**Costs**		
Unit	**Type**	**Capacity**	**Min prod**	**Running**	**Startup**	**Shutdown**
G2	Oil	30	5%	24	10863.2	1086.32
G3	Gas	30	5%	24	5047.7	504.7
G4	Hard coal	50	25%	20	12281.0	1842.15
G5	Nuclear	150	25%	15	0	0
G6	Lignite	50	25%	5	19172	2875.8

Some simple adjustments are then made to the parameters as a high-level sensitivity analysis. Start/stop costs, running costs, capacity, and minimum load are adjusted in turn.

5.4.4 Results

Before looking at system behavior, the solution time is considered. All runs are performed on a Asus Zenbook UX430UQ with 16GB RAM and processor Intel® Core™ i7-7500U CPU @ 2.7GHz, 2904 Mhz with 2 Cores and 4 Logical Processors. Note that some tests have been run simultaneously and all solver settings are the default for Gurobi. No attempts have been made to distribute processing power optimally. All reported performance statistics are retrieved from logs returned by Gurobi, see Appendix C.2 for information on how Gurobi solved LP and MIP problems.

Table 5.5 shows information from the MIP log for the first week of the regular MILP implementation, and the first iteration for the first week of the receding horizon method. Table 5.6 shows statistics for the whole week for the receding horizon implementation.

The statistics on problem size are for the problem after presolve. The number of rows is reduced by ~21 %, the number of columns by ~39 % for both cases, while the number of integer variables increases from 840 to 1508 in the weekly implementation, and from 120 to 212 in the receding.

Table 5.5: MILP performance statistics, weekly and 1st iteration of receding horizon

<table>
<tr><th>Implementation</th><th>week</th><th>rows</th><th>cols</th><th>cont. vars</th><th>bin. vars</th><th>iterations</th><th>solver time</th></tr>
<tr><td rowspan="5">Weekly MILP</td><td>1</td><td rowspan="2">17636</td><td rowspan="4">50242</td><td rowspan="4">48734</td><td rowspan="5">1508</td><td>34167</td><td>10.51s</td></tr>
<tr><td>2</td><td>34649</td><td>11.98s</td></tr>
<tr><td>3</td><td>17640</td><td>33386</td><td>14.03s</td></tr>
<tr><td>4</td><td rowspan="2">17638</td><td>36335</td><td>12.95s</td></tr>
<tr><td>5</td><td>50240</td><td>48732</td><td>34878</td><td>12.76s</td></tr>
<tr><td rowspan="5">Receding horizon (1st iteration)</td><td>1</td><td rowspan="2">15620</td><td rowspan="4">48802</td><td rowspan="4">48590</td><td rowspan="5">212</td><td>34661</td><td>8.22s</td></tr>
<tr><td>2</td><td>30332</td><td>6.52s</td></tr>
<tr><td>3</td><td>15624</td><td>32038</td><td>2.54s</td></tr>
<tr><td>4</td><td rowspan="2">15622</td><td>35643</td><td>2.36s</td></tr>
<tr><td>5</td><td>48800</td><td>48588</td><td>33621</td><td>2.41</td></tr>
</table>

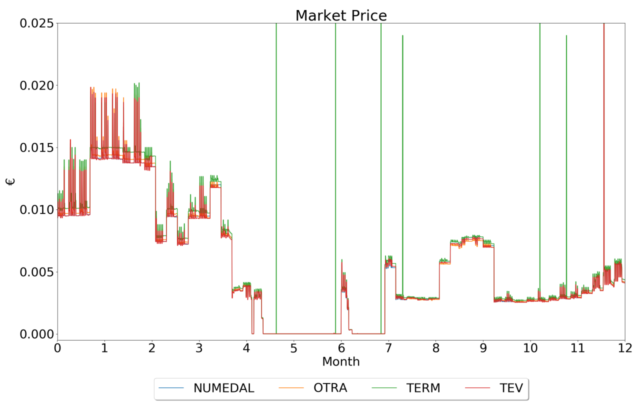
Table 5.6: Receding horizon performance first week

day	**rows**	**cols**	**cont. var**	**bin. var**	**iterations**	**solver time**
1	15620	48802	48590	212	34661	8.22s
2	13436	41866	41654		28838	6.23s
3	11252	34930	34718		22175	4.04s
4	9068	27994	27782		18390	3.16s
5	6884	21058	20846		13169	0.78s
6	4700	14122	13910		7936	1.00s
7	2516	7186	6974		3955	0.18s

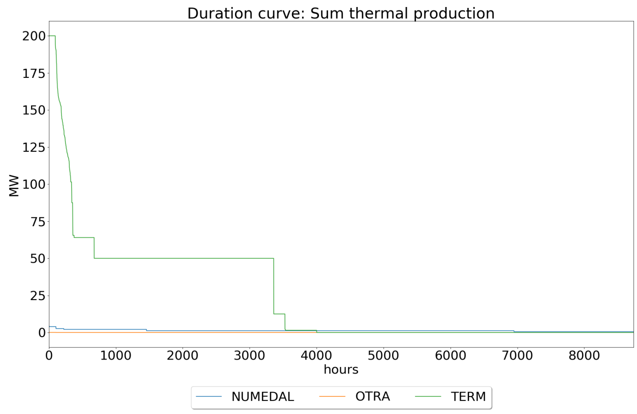
Objective value results are not presented since the structural difference of the implementations make the results incomparable - receding horizon does not compute the objective for the whole week with the final integer solutions after the last iteration.

Gurobi solves MIP problems by applying the branch-and-bound method of Root Simplex. However, the solver does not explore any nodes for any of the runs, because it is able to find a solution with acceptable MIP gap at the root node by applying heuristics.

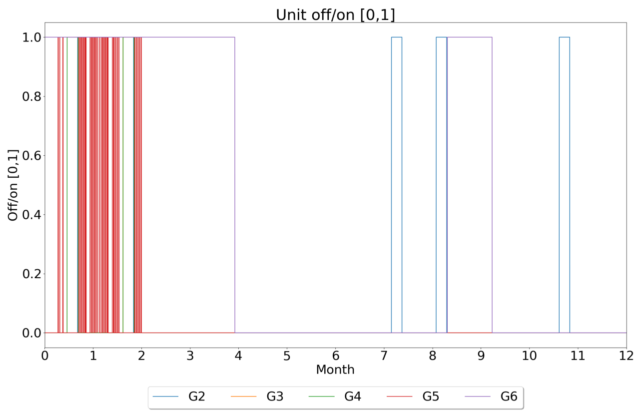
Figure 5.9 shows yearly results for the weekly MILP implementation. For most hours, there is no visible change in the market price of Figure 5.9a compared to the benchmark of Figure 5.5b. There is a significant increase at the end of the second month, as well as some price spikes. Peak price of €3 occurs in one hour for each of the months; 5,6,7,11. Figures 5.9b and 5.9d show that the thermal plants are utilized less than half the year. Considering the plant state in Figure 5.9c and thermal production in Figure 5.9d, it can be observed that all plants are run in the course of a year and that the nuclear plant G5 provides regulating power while the lignite plant G6 runs at full capacity, providing a baseload when used.



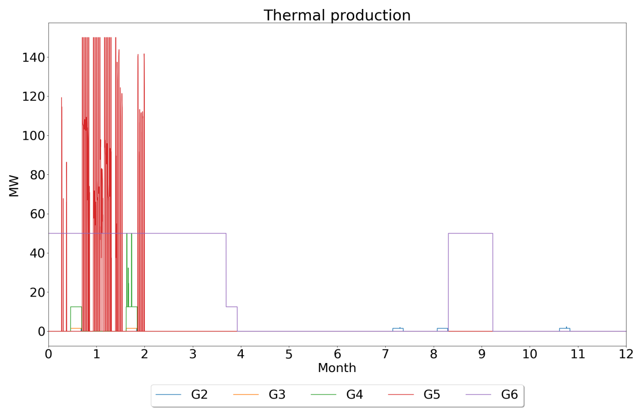
(a) Market price



(b) Duration curve thermal production



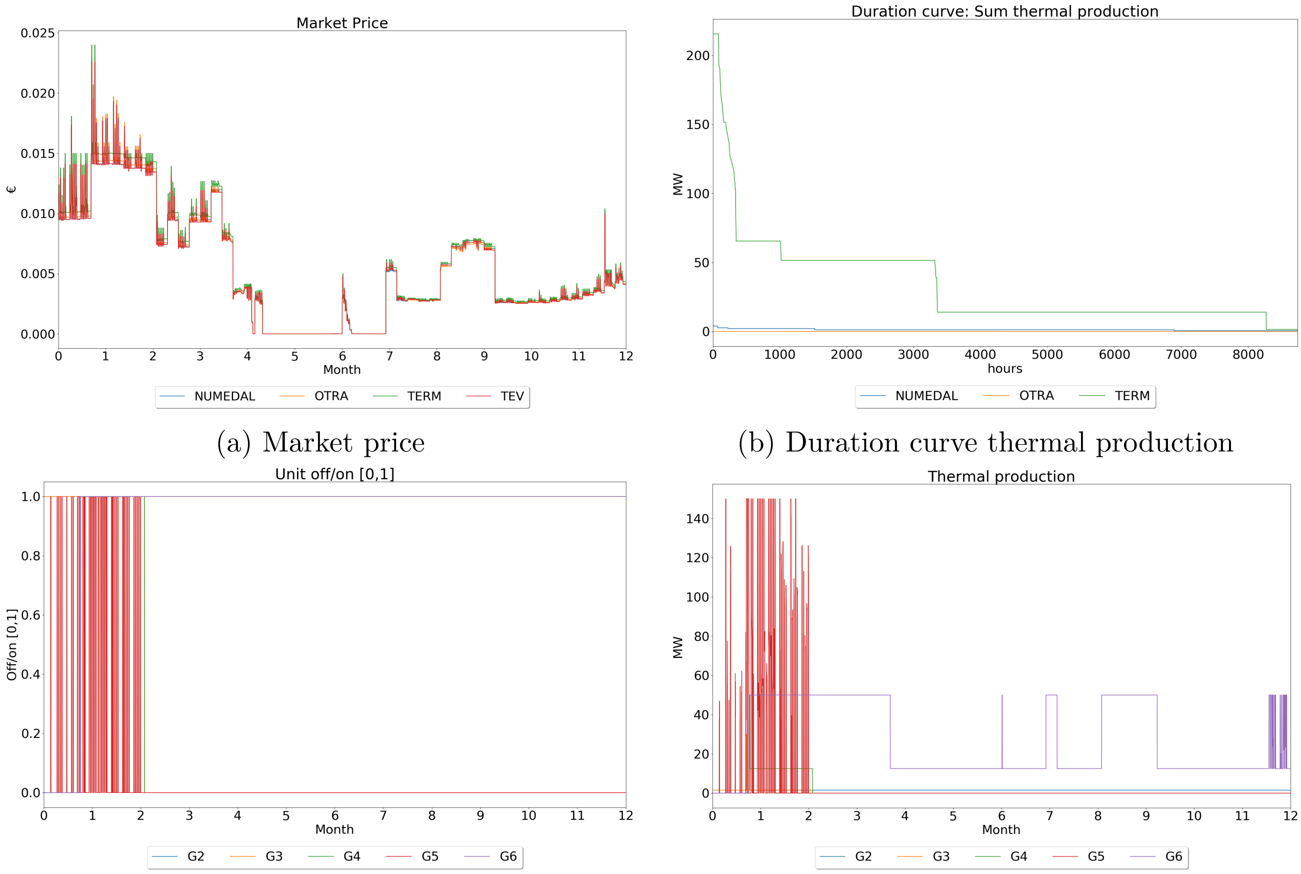
(c) Plant state



(d) Thermal production in Term

Figure 5.9: Thermal results with weekly MILP

The same plots are shown for the system with receding horizon MILP implementation in Figure 5.10. In this case, there are no extreme price spikes. However, Figure 5.10a shows considerably higher prices in the first weeks of the year. Figure 5.10b shows a similar duration curve as before, but now with a base-load of 12.5MW. There is a significant difference in the thermal production schedule, as can be seen from Figures 5.10c and 5.10d. G5 is still used to provide regulating power in the early months, but the lignite plant G6 does not stop once started. Only three plants are used in this case.



(a) Market price

(b) Duration curve thermal production

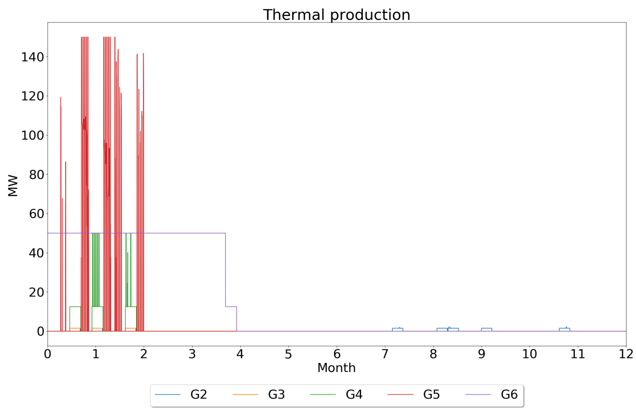
(c) Plant state

(d) Thermal production in Term

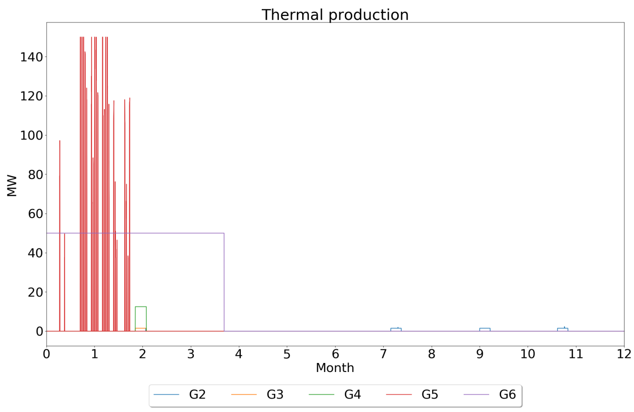
Figure 5.10: Thermal results with receding horizon MILP

Further studies of the thermal system were completed using the weekly MILP structure as the receding horizon implementation is slower and yields non-optimal results.

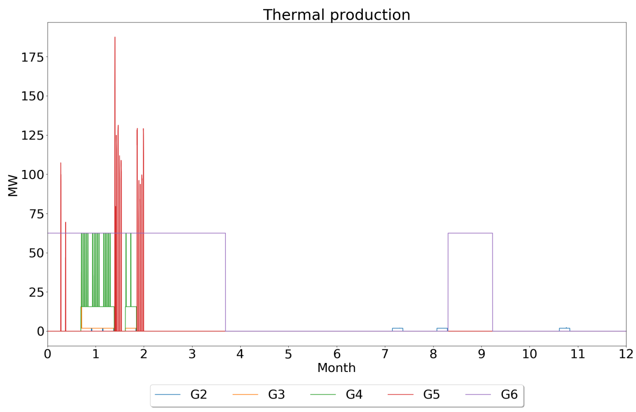
Figure 5.11 shows the thermal production in Term for each of the adjustment cases. Figure 5.11a and 5.11b show that increasing costs will cause the production with G6 in the 9$^{\text{th}}$ month to become unprofitable. Increasing the plant capacities by 25 % makes the nuclear plant unprofitable to use as regulating power. Finally, Figure 5.11d shows that it becomes profitable not to shut down G6 at the end of the year, but rather run at minimum capacity.



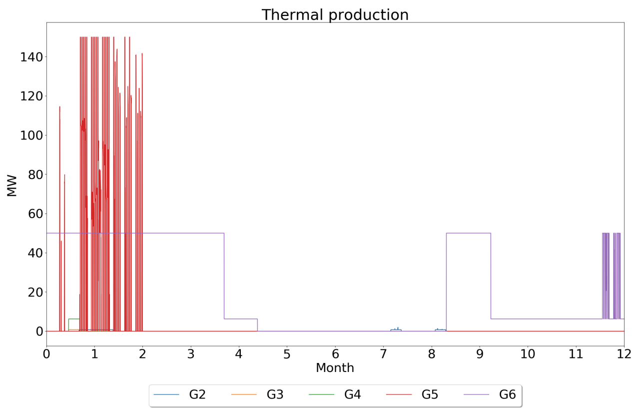
(a) With 25 % increase in start/stop costs



(b) With 25 % increase in running costs



(c) With 25 % increase in capacity



(d) With 50 % increase in minimum load

Figure 5.11: Thermal production with variation in thermal parameters

5.4.5 Discussion

As seen from Table 5.5, the first iteration of the receding horizon implementation is significantly faster than the weekly solution. This is expected as 720 binary variables (1296 after presolve) are removed relative to the regular MILP. However, when considering the whole week solving the receding horizon takes more than twice as long.

Besides, the receding method requires considerable adjustments between iterations, in the current implementation of the method. The binary variables need to be fixed after solving, and the problem is rerun as an LP problem, to obtain water values and market prices from the dual formulation. The first 24 hours are then deleted from the set of time steps $\mathscr{K}_t$ and the hours to have; the model must then be reconstructed as this indexes most variables, parameters, sets, and constraints. A possibly better solution would be to fix all variables for the solved MILP hours, update the MILP hours set ($\mathscr{K}_t^{MILP}$), and resolve. Here, it would not be necessary to reconstruct the model, but possibly still some of the constraints that are indexed by the MILP hours set.

Considering the model results the price spikes at €3 in the weekly implementation were found to coincide with load rationing in Term, shown in Figure B.4. Though the rationing is minimal at ~1.35MW, the price effect is substantial due to the high rationing cost at €3000/MW. Still, considering the power is only need for one hour, it is cheaper to ration than to start and stop a unit. The other price increases correspond with when thermal units are started and stopped. The nuclear unit G6 is used for regulating as it has no associated startup and shutdown costs.

In comparing the two cases, considerable differences have been observed. This suggests that the receding horizon implementation is not optimal. The differences in the solutions stem from how the thermal units are allowed to operate. Since the thermal costs are enforced only during the 24 first hours of each receding iteration, the solver will rather wait with starting or stopping a unit. Then, in the next iterations, the costs suddenly appear. Hence, G5 is never turned off as it is cheaper to run at minimum load than to turn the unit off. Since the unit is running, there is no need for rationing in this case.

Based on the system behavior with receding horizon, it is clear that further restrictions should have been included for the thermal units in the LP period of the week. For example by using an LP based approximate algorithm, here from [33]. This approach is used in large-scale systems, to avoid excessive calculation times. Each plant is then represented by four variables taking values from 0 to 1, under the following constraints:

$$P_{ik}^{th} = X_{1,ik}^{th}\underline{P}_i^{th} + X_{2,ik}^{th}(\overline{P}_i^{th} - \underline{P}_i^{th}) \qquad \forall i \in \mathscr{P}_a, k \in \mathscr{K} \tag{5.8}$$

$$X_{1,ik}^{th} \geq X_{2,ik}^{th} + X_{3,ik}^{th} \qquad \forall i \in \mathscr{P}_a, k \in \mathscr{K} \tag{5.9}$$

$$X_{2,ik}^{th} + X_{3,ik}^{th} \leq 1 \qquad \forall i \in \mathscr{P}_a, k \in \mathscr{K} \tag{5.10}$$

$$X_{1,ik}^{th} - X_{1,ik-1}^{th} \leq Str_{ik}^{th} \qquad \forall i \in \mathscr{P}_a, k \in \mathscr{K} \tag{5.11}$$

$\underline{P}_i^{th}, \overline{P}_i^{th}$	minimum and maximum available generation capacity of unit i, respectively, (MW)
$X_{1,ik}^{th}$	per unit production between 0 and the minimum production of thermal unit i at time step k, $\in [0,1]$
$X_{2,ik}^{th}$	per unit production between the minimum and the maximum production of thermal unit i and time step k, $\in [0,1]$
$X_{3,ik}^{th}$	per unit share of spinning reserve capacity of thermal unit i at the time step k, $\in [0,1]$
Str_{ik}^{th}	approximate relative start-up cost of thermal unit i at time step k, $\in [0,1]$

Furthermore, the thermal units would be implemented under the assumption that base-load power plants such as nuclear power plants are always running. These units are usually only taken down for maintenance, which requires a different scheduling problem formulation. Startup and shutdown costs are then taken into account for mid- and peak-merit units such as coal and gas-fired power plants.

Though the results show that the results from the receding horizon implementation are not optimal and take longer to obtain, the methodology might still be interesting, if implemented correctly. It may be that each iteration of the receding implementation would be faster with a better implementation for the thermal units. Also, models that are solved by heuristics report large variations in runtime as random effects profoundly influence heuristics.

Finally, the strength of receding horizon lies in the ability to deal with unpredictable changes. Thus, it might perform better for solving a stochastic problem. In summary, the method should not be rejected, but the implementation improved and tested in situations where its strengths come to play.

5.5 Case 5: Future power system

This case considers the model in its primary application of scheduling in a future power system. The case data is loosely based on the expected changes in Section 2.1.3, using data from previously referenced sources. However, the data had to be adjusted to be in relative size to the original *4del* data.

5.5.1 Methodology

As the ultimate application for the model is for studying a future power system, it is important to verify that the system can handle the expected characteristics. Though the future is unknown, there are strong tendencies towards the changes outlined in Section 2.1.3. This final case becomes a combination of the previous cases, with an addition of more extreme data. The following changes have been implemented in the system:

- More renewables; wind and solar
- Increased demand
- Increased inter-country transmission (HVDC lines)
- Decommissioning of nuclear
- Decommissioning of fossil plants
- Looser ramping constraints
- Increased hydropower capacity, through the installation of turbines and pumps

Solar and thermal power production are introduced in the thermal area with an associated increase in load, representing a future connection of Germany to the Nordic region. The share of renewable generation is based on [18], while load and capacity factors for solar were downloaded from NordPool. Solar is implemented similarly to wind; a deterministic reduction in load based on installed capacity and capacity factors. The resulting final problem formulation of PriMod-NTNU is included in Appendix D.

Plants in Germany are included, based on the data from the TWENTIES project. While for the capacity ratio of each plant type, and relative change is based on Figure 2.5. Referring to the findings of [30], the wind capacity in Norway is increased, with an associated increase in load. Ramping limits are set assuming a 15-minute market.

5.5.2 Results

Table 5.7 summarizes the solver performance results for this case. The problem size has increased with the introduction of ~5000 new constraints and 2178 binary variables. Yet, the solver time is significantly shorter than for Case 4, Table 5.5.

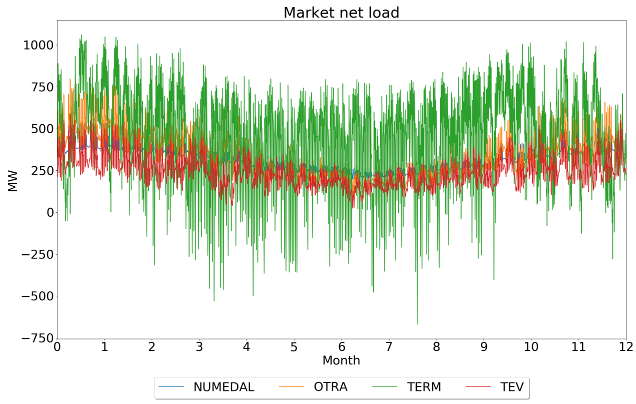
For week 5 the solver found two heuristic solutions for weeks 4-5, such that the solver explored one branch. In the case of week 5, the solver found a new solution by using MIP heuristics. Interestingly, the solution time is cut approximately in half compared to the original start/stop case, despite having introduced 2178 new binary variables almost 5000 constraints.

Table 5.7: Solver performance in future case

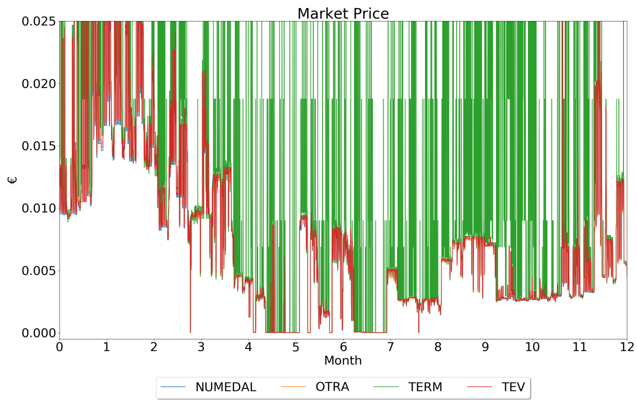
<table>
<tr><th>day</th><th>rows</th><th>cols</th><th>cont. var</th><th>bin. var</th><th>iterations</th><th>solver time</th></tr>
<tr><td>1</td><td>22666</td><td rowspan="3">54940</td><td rowspan="3">51254</td><td rowspan="5">3686</td><td>34845</td><td>6.74s</td></tr>
<tr><td>2</td><td>22665</td><td>30264</td><td>5.80s</td></tr>
<tr><td>3</td><td>22670</td><td>34174</td><td>5.46s</td></tr>
<tr><td>4</td><td rowspan="2">22668</td><td>54939</td><td>51253</td><td>36218</td><td>6.60s</td></tr>
<tr><td>5</td><td>54938</td><td>51252</td><td>36836</td><td>6.45s</td></tr>
</table>

Figure 5.12 shows that the system is high variability. During the summer months, Figure 5.12a shows negative net load in Term for many hours, but still a reasonably stable daily peak load. None of the areas have prominent seasonal variability. Figure 5.12b finds extremely volatile prices, primarily in the upwards direction, with considerable amounts of rationing. Still, the price has mostly the same profile as the benchmarking case (Figure 5.5b) that are strongly dependent on the hydro system.

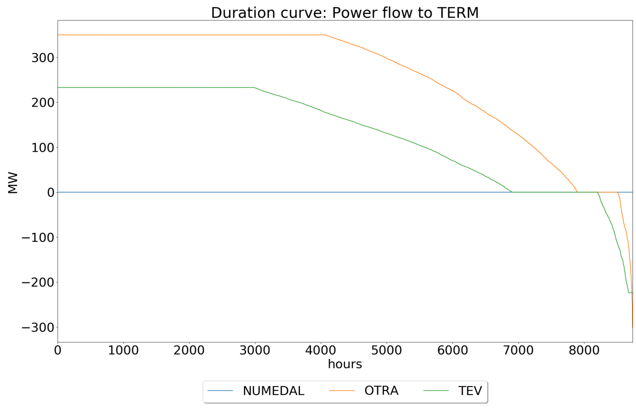
Figure 5.12c shows that the HVDC lines are utilized at full capacity, with flow Term as a net importer, for 34 % and 48 % of the year, on the lines from TEV and Otra respectively. From Figure 5.12d little change can be seen in the profiles for hydro production in Numedal and Term, apart from an increase (shift) in the production in TEV. Otra shows a significant increase in production, and the clear distinction of peak production has disappeared. Figure 5.12e again show small changes in TEV and Numedal, with increased storage in months 9-11, and somewhat faster emptying or reservoirs in months 2-3 in TEV. Numedal experiences a more significant change with a lower bottom level in the 5$^{\text{th}}$, and higher storage levels from there through to month 11.



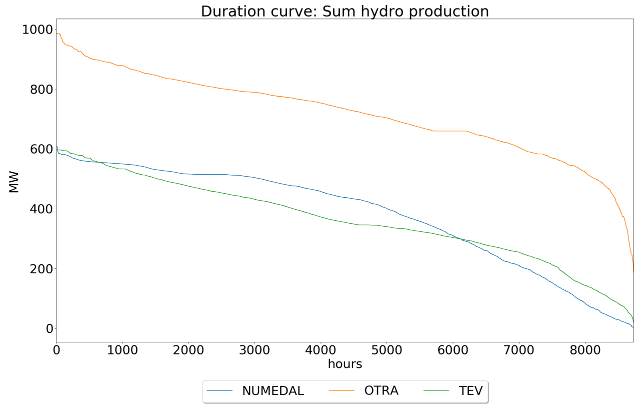
(a) Net load



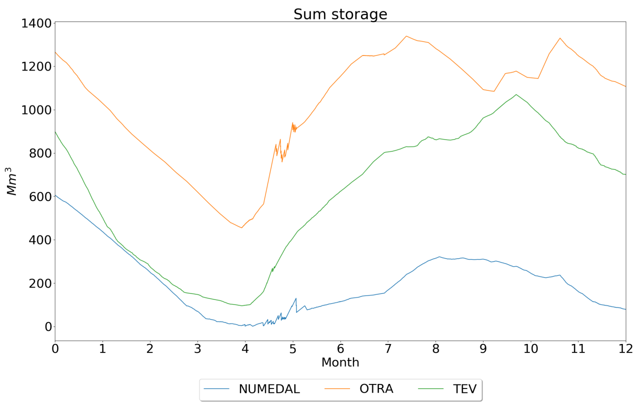
(b) Market price



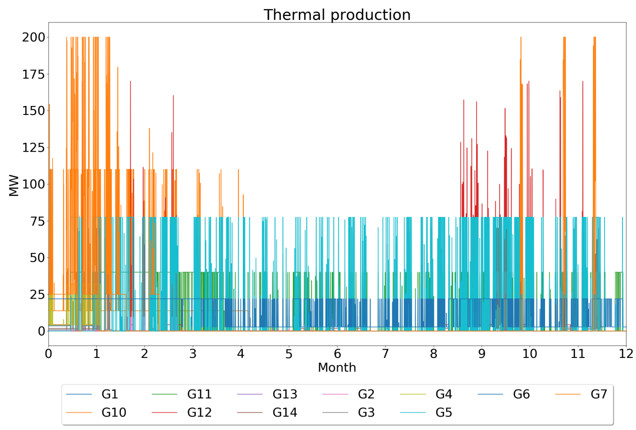
(c) Duration curve power flow to Term



(d) Duration curve for hydro production



(e) Hydro reservoir storage level



(f) Thermal production in Term

Figure 5.12: Future power system results

The behavior of thermal units are unchanged, with no unit providing base-load through the year, but many providing regulating power. Units are mostly running at either maximum or minimum capacity when in operation.

5.5.3 Discussion

Considering the obtained results, this case is undoubtedly extreme, as was intended. For the thermal area to have negative net load every day through the summer, caused by the combination of low load and high SPP, is probably not that likely. However, it makes for an interesting study. e

It is clear that in this system, balancing power is a commodity in high demand, with unpredictable fluctuations and huge load variations within a day. The extremely volatile prices occur due to considerable rationing in the system. The system is limited by the transmission capacity, which hinders the Nordic hydro from providing sufficient balancing power. With such rapid and extreme changes, it is understandable that secure system operation becomes difficult, and that a market with 15-minute clearing would enable safer and more optimal operation.

As a remark; the cuts used in this model can no longer be assumed to provide optimal signals to the problem, considering the major changes that have been made to the data.

Chapter 6 | Conclusion and further work

All code is available for use within NTNU, under an agreement with SINTEF. The work has been documented using BitBucket[1], so all developments can be traced back by future Master's students and Ph.D. candidates as well as researchers at the institute who wish to continue development of this code.

The thesis has considered a model under development, and the main contribution of the thesis is the model implementations and the identification of shortcomings and possibilities for improvement. The results obtained in the studies have not correctly reflected normal system behavior, indicating that significant changes should be made to the implementations. Improvements that have been identified for the model are:

- Improve implementation of thermal conditions: base-load plants should be defined as running at all times, to avoid unrealistic, frequent starting and stopping of these units. Startup and shutdown costs are then considered for mid- and peak-merit power plants.
- Updating of receding horizon method, this enhancement consists of two steps; First, the structure for moving to the next iteration within a week should be updated to avoid the restructuring of the model for each iteration. Second, a linear approximation of the thermal unit commitment with startup and shutdown costs should be implemented to obtain more realistic and better results when using the receding method.
- Sharpen the problem formulation, to ensure model robustness and avoid numeric issues. This entails scaling of the model to fulfill suggested spread limits on problem

[1] `https://bitbucket.org`

matrix, bounds, and objective. Moreover to consider whether the constraint and objective are optimally formulated.

- Investigate possible bug(s) in the market price.
- Developing the calculation of socio-economic surplus, for use as a key performance index in comparisons of cases.
- Test the model with different input data, to test robustness and performance considering larger systems.

In addition to improving the existing implementations, it is important to continue the model development if it is to be used for power system studies in a future power market. The list below, which is not exhaustive, contains suggestions for further development of the problem. The choice of implementations must be based on the desired strengths of the model, more explicitly defined than ”modeling the future power system.” The model must be sufficiently limited to avoid over-complexity, making the model large and unsolvable within a reasonable time. The development choice can be based for example on the goal of having a detailed description of the hydro system, or to have a formulation that depicts the dynamics between hydro, thermal and variable power production. Some recommended developments are:

- Implement maximum up-time, and minimum downtime for thermal units. This is important to obtain a realistic schedule where thermal units are not impossibly scheduled to provide regulating power or to provide base-load at full capacity for too long.
- Generation ramping constraints are generally not included being outweighed by increased system complexity. It is still unknown how the model performs when solving for large systems, so generation ramping may be realistic to implement and can give considerable value to the model.
- Model stochasticity in inflow, wind- and solar power production. The conversion to a stochastic mixed integer linear programming model should be considered an essential step for realistic modeling of a future ”green” power system.
- Change to 15-minute scheduling periods, to allow for better handling of system variability.
- Introduce water delay, and loss in waterways where the impact on scheduling is significant.

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Chapter A | Module name reference

These tables are included to allow the reader to interpret the results of the evaluated cases while considering the system structures in Section 3.1.

Table A.1: Name to module reference for Otra hydro system

Plant name	Reservoir name	Module ID
	Urarvatn	142
	Ormsa	143
	Skyvatn	144
	Breivåsev	145
	Førresvatn	146
Holen	Vatnedal	11513
	Hartevann	148
	Hoslåsarv	149
Brokke	Bossvatn	11511
	Bykil	151
	Valle	152
	NDF Brokke	153
Hovatn	Hovatn	154
	Longerakvatn	155
	Byglandsfjor	156
	Gyvatn	157
Iveland	Iveland	11505
Nomeland		159
Steinsfoss	Steinsfoss	160
Hunsfoss	Hunsfoss	161
Vigeland	Vigeland	162

Table A.2: Name to module reference for TEV hydro system

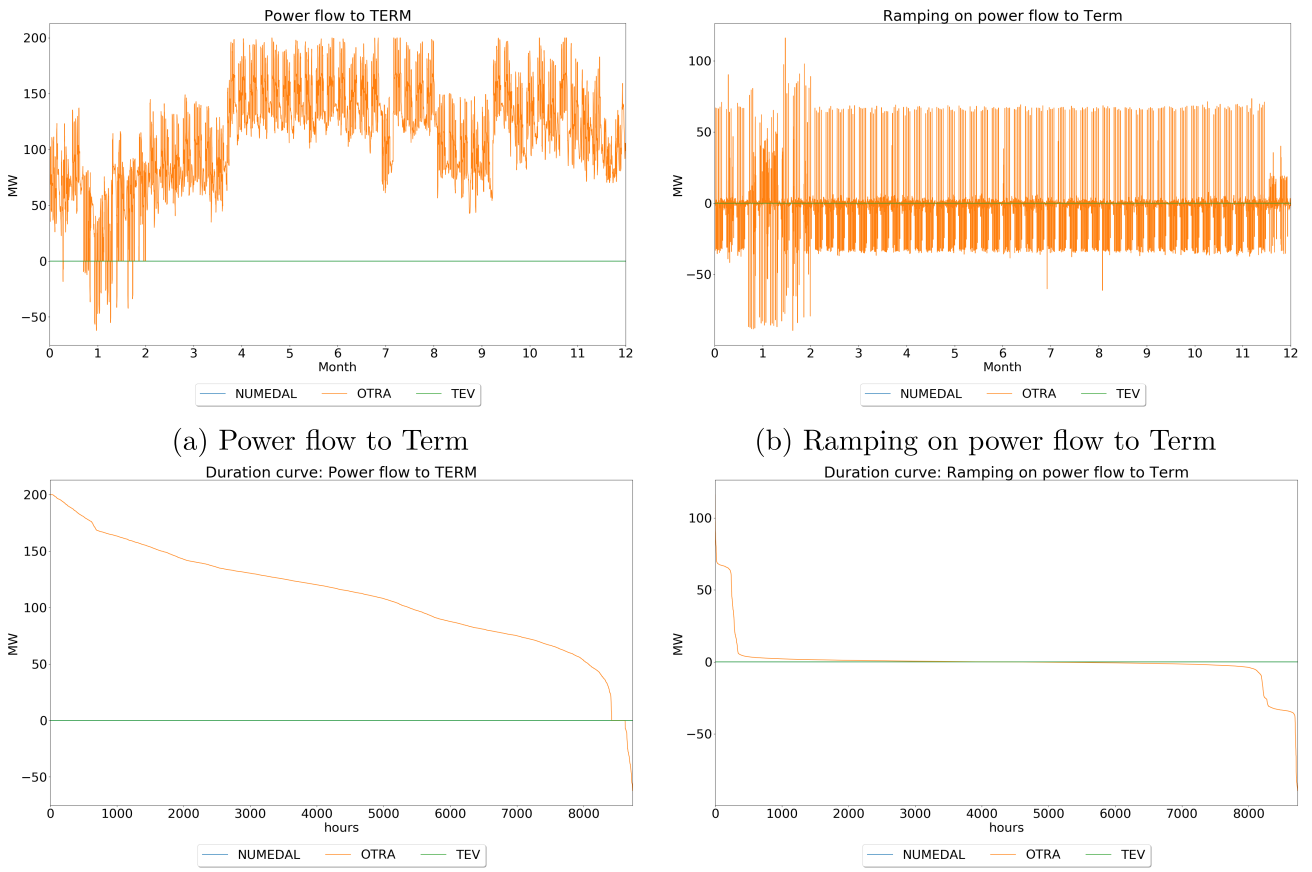
Plant name	Reservoir name	Module ID
Julskaret	Sørungen	49906
Slindelva	Slindvatn	49905
Tya	Tya	49909
Nedalsfoss	Sylsjø	49912
Vessingsfoss	Nesjø	49911
Nea	Vessingsjø	49910
Gresslifoss	Gresslifoss	49908
Hegsetfoss	Hegsetfoss	49907
Bratsberg	Selbusjøen	49904
Svean & Løkaun	Svean & Løkaun	49903
Fjæremsfoss	Fjæremsfoss	49902
Leirfoss	Leirfoss	49901

Table A.3: Name to module reference for Numedal hydro system

Plant name	Reservoir name	Module ID
	Halnefjord	7301
	Pålsbufjord	7302
Nore 1	Tunnhovfjord	7303
Nore 2		7304
Uvdal 1	Uvdal 1	7305
Uvdal 2	Uvdal 2	7306
Mykstufoss	Mykstufoss	7307
Djupdal	Djupdal	7308
	Kyrkjevatnet	7309
Hølseter	Hølseter	7310
Vrenga	Vrenga	7311
Pikerfoss	Pikerfoss	7312
Nybrofoss	Nybrofoss	7313
Gamlebrofoss	Gamlebrofoss	7314
Skollenborg		7315
Labro		7316
Vittingfoss	Vittingfoss	7317

Chapter B | Additional case study results

B.1 Case 2: Benchmark



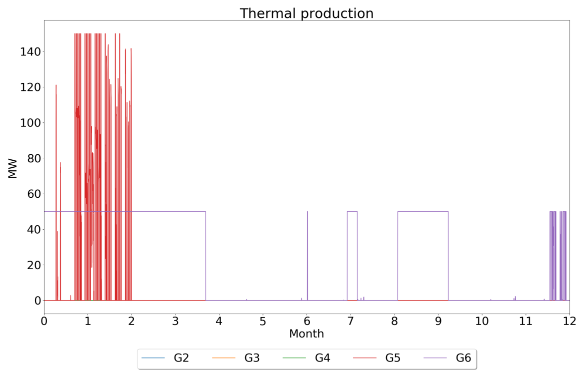
(a) Power flow to Term

(b) Ramping on power flow to Term

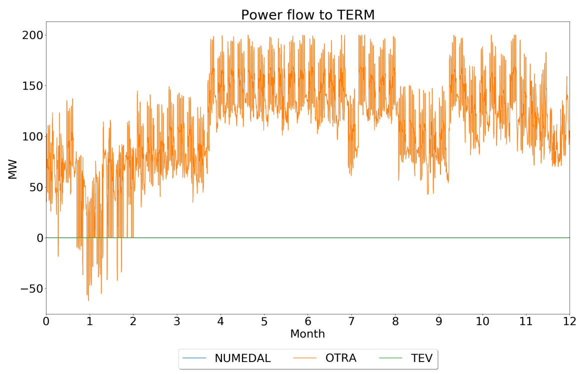
(c) Duration curve power flow to Term

(d) Duration curve ramping on power flow to Term

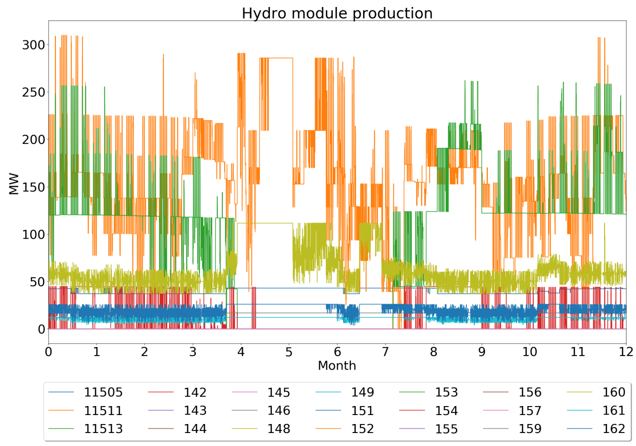
Figure B.1: Plots for power flows to Term, benchmark case



(a) Thermal production in Term



(b) Power flow to Term



(c) Hydropower production in Otra

Figure B.2: Results for benchmarking case

B.2 Case 3: Ramping

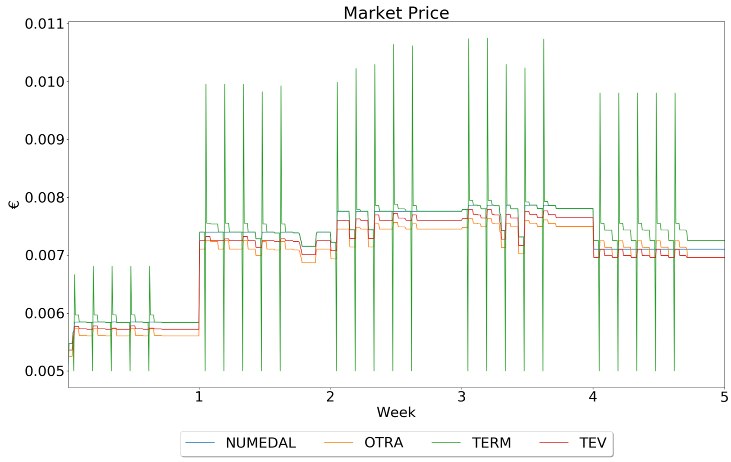


Figure B.3: Original market price in ramping case with one line and 28.6 % limit

B.3 Case 4: Start/stop

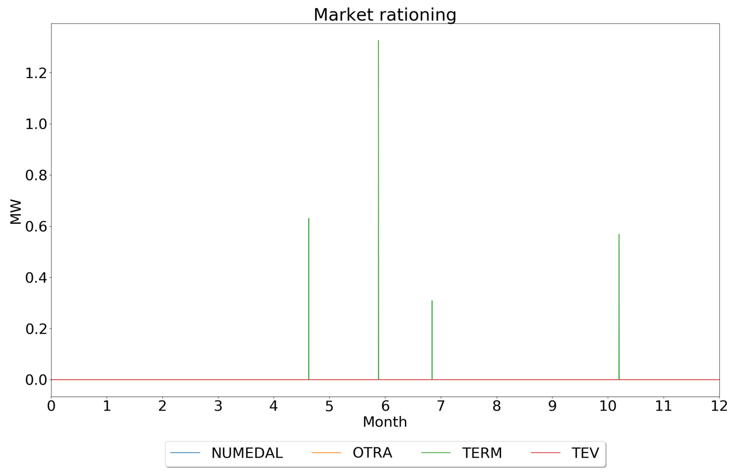


Figure B.4: System rationing in weekly start/stop case

Chapter C | Applied software

C.1 Pyomo

The model used in this thesis is developed in Pyomo, and open-source optimization software package implemented in Python. The package supports a diverse set of capabilities for formulating, solving and analyzing optimization models.

The user can choose to define general symbolic problems (abstract models) or create specific problem instances (concrete model), and solve them using commercial and open-source solvers. Since the software is implemented within Python, it has access to the rich set of supporting libraries found in the language [20][21].

When used with the appropriate solver, Pyomo supports a wide range of optimization problem types. For the completed work, the open-source solver Gurobi has been applied. Gurobi supports the necessary problem types; LP and MILP [22], and solves them as described in the next Section C.2.

C.2 Gurobi

This appendix includes a short description of how Gurobi solves the LP and MIP problems of this thesis. A section on the reason of and effect of numeric issues, as well as how to avoid them is included as they were encountered during the development.

C.2.1 Linear program

The problem is solved using a barrier algorithm (interior point method).

A linear program is solved through 5 steps [42]:

- Presolve: removes redundant rows and columns from the problem's A-matrix
- Barrier preprocessing: computes a fill-reducing reordering of rows and columns in factor matrix
- Solving: solves the problem in iterations using the barrier method
- Crossover (uncrushing): converts interior point solution to a basic solution which is passed to simplex and optimized

If the barrier method encounters numerical issues, the problem is attempted solved with dual simplex instead.

C.2.2 Mixed integer program

The problem is solved using the branch-and-bound method of root simplex.

A mip problem is solved in 4 steps [43]:

- Presolve: removes redundant rows and columns from the problem's A-matrix
- Heuristics: the solver may find one or more heuristic solutions
- Solving MIP: solves the problem in iterations of root simplex
- Optimal solution: uses root relaxation

C.2.3 Numeric issues

During the model development, it was discovered that PriMod is subject to numeric issues. These issues can have great impact on solver performance, and cause undesirable events, such as:

- Long solving times
- Solver gives optimal solution that actually sub-optimal or infeasible
- Impossible to solve within reasonable time, causing time-out
- Claiming model to be infeasible or unbounded

Proper scaling of the model is crucial to avoid numeric issues. In good practice, the spread between the smallest and largest matrix coefficients should <1e6. Further, the largest bound and objective coefficient should <1e8.

to improve upon poor bounds, they can either be tightened scaled to allow for tightening. If variables have very large bounds is is also possible to set the limits to infinity or declare as a free variable, given that the variable is otherwise constrained in the model

In PriMod, the solver gave numeric issue warning with spread of 10^{12} for the objective and bounds range, giving the future profit variable α infinite bounds resolved this issue, though the spread is still 10^{11} and 10^{10} for the objective and bounds respectively. The solving time decreased by 6 % as a result of the bounds change. In general, carefully defining the problem can significantly improve performance.

Chapter D | Optimization problem: PriMod-NTNU

Here, the final mathematical formulation of the NTNU PriMod model instance is presented. This model is stored on BitBucket, available for future Master students and PhD Candidates for further development, under agreement with SINTEF Energy.

Indices

a	system area
k	time step
t	week
r	reservoir
j	unit, segment
c	cut
i	other area, other reservoir

Index sets

$\mathscr{A}$	set of price areas
$\mathscr{T}$	set of weeks
$\mathscr{K}_t$	set of time steps in week t
$\mathscr{C}_t$	set of Benders cuts for week t
$\mathscr{W}_a$	set of wind parks in area a
$\mathscr{R}_a$	set of reservoirs in area a
$\mathscr{R}_a^{reg}$	set of regulated reservoirs in area a
$\mathscr{R}_a^{ureg}$	set of unregulated reservoirs in area a
$\mathscr{R}_r^{up}$	set of upstream reservoirs destination at r
$\mathscr{N}_r^{PQ}$	segments in piecewise-linear PQ-curve for reservoir r
$\mathscr{P}_a$	set of thermal plants in area a

Parameters

Tr_i^{loss}	transmission loss to area i, fraction (0,1)
L_k	aggregated load, (MW)
W_k	wind production, (MWh)
S_k	solar production, (MW)
F^C	cost of market flooding, (€ /MWh)
R^C	cost of load curtailment, (€ /MWh)
η_{rj}	generation efficiency per PQ-curve segment j, (MW/m^3/s)
H_r	relative head (h/h$_0$) at reservoir r, refers to initial reservoir level
Pum_r^{pow}	pumping power from reservoir r, (MW/m^3/s)
$\mathcal{P}^S$	penalty for spillage, (€ /m^3/s)
$\mathcal{P}^B$	penalty for bypass, (€ /m^3/s)
$\mathcal{P}^{tank}$	penalty for tanking, (€ /m^3/s)
I_{rk}^{reg}	regulated inflow to reservoir r, (Mm^3)
I_{rk}^{ureg}	unregulated inflow to reservoir r, (Mm^3)
β_c	Benders cut right-hand side for cut c, (10^3 €)
π_{rc}	Benders cut coefficient for reservoir r and cut c, (10^3 €/Mm^3)
C_j^{start}	startup cost of unit j, (€)
C_j^{stop}	shutdown cost of unit j, (€)
T_j^C	running cost of thermal unit j, (€ /MWh)
T^{cap}	capacity of thermal unit j, (MW)
T_j^{min}	minimum load of unit j when running, (MW)

Decision variables

tr_{jk}	transmission between areas i and j, (MW)
x_{rk}	reservoir level for r, (Mm^3)
q_{rk}	release form reservoir r, (m^3/s)
q_{rjk}^D	discharge through station r per segment j, (m^3/s)
q_{rk}^B	bypass from reservoir r, (m^3/s)
q_{rk}^S	spillage from reservoir r, (m^3/s)
q_{rk}^P	pumping at r, (m^3/s)
q_{rk}^T	tunnelling from reservoir r, (m^3/s)
α	future profit function, (10^3 €)
ph_{rk}	production from module/reservoir r, (MW)
f_{ak}	market flooding in area a in time period k, (MW)
r_{ak}	load curtailment in area a in time period k, (MW)
$tank_{jr}$	tanking for reservoir r, (m^3/s)
u_{jk}	unit j running, *binary*
v_{jk}^+	unit j started, $\in [0,1]$
v_{jk}^-	unit j stopped, $\in [0,1]$
t_{jk}	production from unit j, (MW)

$$
\begin{aligned}
\min \quad & \sum_{a\in\mathscr{A}}\Bigg(\sum_{k\in\mathscr{K}}\bigg(F^C f_{ak} + R^C r_{ak} + \sum_{j\in\mathscr{P}_a} T_j^C t_{jk} + \sum_{r\in\mathscr{R}_a}(\mathcal{P}^S q_{rk}^S + \mathcal{P}^B q_{rk}^B) \\
& + \sum_{j\in\mathscr{P}_a}(C_j^{start} v_{jk}^+ + C_j^{stop} v_{jk}^-)\bigg) + \sum_{r\in\mathscr{R}_a}\mathcal{P}^T tank_r\Bigg) + \alpha
\end{aligned}
$$

s.t.

$$
\sum_{r\in\mathscr{R}_a}\Big(\sum_{j\in\mathscr{N}_r^{PQ}} H_r \eta_{rj} q_{rjk}^D - Pum_r^{pow} q_{rk}^P\Big) + \sum_{j\in\mathscr{A}}\Big(tr_{to,jk}(1 - Tr_j^{loss}) - tr_{from,jk}\Big)
$$

$$
+ F^C f_{ak} + R^C r_{ak}\sum_{j\in\mathscr{P}_a} T_j^C t_{jk} = L_k - W_k - S_k,
$$

$$
x_{rk} - x_{rk-1} + q_{rk} + q_{rk}^S + q_{rk}^P + q_{rk}^T - \sum_{i\in\mathscr{R}_r^{up}}(q_{ik} + q_{ik}^S + q_{ik}^P + q_{ik}^T) = I_{rk}^{reg},
$$

$$
\sum_{j\in\mathscr{N}_r^{PQ}} q_{rjk}^D + q_{rk}^B - q_{rk} = I_{rk}^{ureg},
$$

$$
-Tr_{aj}^{ramp} \le (tr_{ajk} - tr_{jak}(1 - Tr_{aj}^{loss})) - (tr_{ajk-1} - tr_{jak-1}(1 - Tr_{aj}^{loss})) \le Tr_{aj}^{ramp},
$$

$$
v_{jk}^+ - v_{jk}^- = u_{jk} - u_{jk-1},
$$

$$
T_j^{min} u_{jk} \le t_{jk} \le T_j^{cap} u_{jk},
$$

$$
\sum_{j\in\mathscr{N}_r^{PQ}} q_{rjk}^D + q_{rk}^B - q_{rk} = I_{rk}^{ureg},
$$

$$
\alpha - \sum_{a\in\mathscr{A}}\sum_{c\in\mathscr{C}_t}\sum_{r\in\mathscr{R}_a^{reg}} \pi_{rc} x_{rk} \ge \sum_{c\in\mathscr{C}_t}\beta_c,
$$

$$
\sum_{j\in\mathscr{N}_r^{PQ}} H_r \mu_{rj} q_{rjk}^D = ph_{rk}
$$

In addition, there are relevant bounds on all decision variables.