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Water Behind Capacity

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Preface

This master's thesis is the result of the final project carried out as part of the Master of Science degree in Energy Planning and Environmental Analysis at the Norwegian University of Science and Technology, Department of Electric Power Engineering. The project has been completed during the spring semester of 2016, and has been part of the scientific cooperation between the university and SINTEF Energy Research.

During the work of this project, I have had excellent guidance from my supervisors Magnus Korpås and Ellen Krohn Aasgård, of which I am very grateful. In addition to his excellent guidance and contribution to the work, I am very thankful and impressed by Korpås' wish to guide as many students as possible. Of equal importance, Aasgård has been very helpful in assisting me with the problems I have met. She has made a great contribution to the work, with her expertise in the subject, as well as bringing up the idea to the project. Additionally, I am very grateful for the data Statkraft and Hydro Energi has provided me, and I would especially like to thank Ole Løseth Elvetun at Hydro Energi for helping me with his industrial points of views. I would also like to thank Finn Erik Ljåstad Pettersen, Eivind Lindeberg, Erik Alexander Jansson and Gerard Doorman at Statnett for providing me helpful information about the balancing markets.

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Executive Summary

When the power system becomes more dependent on intermittent renewable energy, the need for ancillary services becomes larger. Therefore, the power producers' ability to deliver reserves has been analysed in this thesis. Additionally, the costs of delivering such services have been evaluated, as these costs determine if it is profitable for hydro power producers to supply balancing power instead of energy. Since hydro power is a well suited source for delivering balancing power, and a major part of the Nordic power system, the amounts of reserves which can be delivered from hydro power units have been the main topic of this thesis.

The thesis is based on the decision support tool SHOP, which is a short term optimization model for hydro power producers developed at SINTEF Energy Research, in addition to its newly developed simulation funcionality. The model is one of the industry's most used tools for finding the optimal amount of energy to be sold in the power market in every hour for the days to come. However, the model is not adequate for deciding the amount of reserves to be be delivered, and does not consider hydrological constraints when the reserves are activated. Therefore, the first objective in this thesis has been to develop a methodology for assessing the amounts of reserves which can be delivered. In order to do this, the methodology has been based on the excising models, and the model functionalities have been utilized in innovative and non-standard ways. Next, the second objective in this work has been to validate the methodology on illustrative and realistic case studies.

From the results in the analysis, it has been shown that the developed methodology successfully assesses the amounts of reserves which can be delivered, and produces realistic results. Hence, the results are not only verifying the methodology, but are also illustrating concepts which are very valuable for market participants who are delivering ancillary services. Furthermore, it has been shown that the costs and amounts of reserves which can be delivered from a hydro system in the regulating power option market are strongly related to the amount of available water in the system's reservoirs. Additionally, the hydro system's flexibility also plays an important role, as more reserves can be delivered from a less constrained system. As more flexibility is available when reserves are delivered from a hydro system which consists of several cascaded plants,

more reserves can typically be delivered from such systems, and at lower costs.

The analysis has been carried out in several steps. First, the expected number of hours which the reserved capacity is activated has been found. This estimate is based on available historical data of the Nordic power system, and statistical methods have been used to find the expected number. Next, the maximum amount of capacity which can be activated from a hydro system during the expected time period without emptying the system's reservoirs has been found. Finally, the costs of delivering different amounts of reserves have been found. The analysis has been carried out on two different hydro systems, where different amounts of generation capacity have been reserved for the regulating power option market, and the amounts of available water in the reservoirs have been varied.

At last, it has been shown that the amounts of reserves which actually can be delivered are limited, even though the system easily can withhold more generation capacity from the generating units. This is both due to water unavailability and violation of hydrological constraints when the reserved capacity is activated. Hence, in order to obtain decision support tools which are well suited for production scheduling in several markets, the excising models should be extended to include algorithms which assess the volumes that can be delivered in the balancing markets while considering the risk of violating relevant constraints.

Samandrag

Når kraftsystemet vert avhengig av meir uregulerbar og fornybar energi, aukar behovet for balansetenester. Derfor har kraftprodusentar si evne til å levere reserver til kraftsystemet blitt analysert i denne oppgåva. Dessutan har kostnaden knytt til å levere reserver også blitt evaluert, ettersom desse kostnadane avgjer om det er lønsamt å levere reservekraft i tillegg til ordinær kraft. Sidan vasskraft er veldig godt egna til å levere balansekraft, og er ein stor del av det nordiske kraftsystemet, har mengda reserver som kan leverast frå vasskraft vore hovudtemaet i denne oppgåva.

Oppgåva er basert på beslutningsstøtteverktøyet SHOP, som er ein korttids optimaliseringsmodell for kraftprodusentar utvikla av SINTEF Energi, i tillegg til dens nylig utvikla simuleringsfunksjonalitet. Denne modellen er ein av industriens mest brukte verktøy for å finne optimal produksjon av vasskraft for kvar time dei påfølgande dagane. Modellen kan derimot ikkje ta slutning til mengda reserver som kan leverast, og tek heller ikkje hensyn til hydrologiske restriksjonar når reserver vert aktivert. Difor har det første føremålet med denne oppgåve vore å utvikle ein metodikk for å vurdere mengda reserver som kan leverast. Denne metodikken har blitt basert på eksisterande modellar, og funksjonaliteten til modellane har blitt utnytta på innovative og kreative måtar. Det andre føremålet med denne oppgåva har vore å validere metodikken på illustrative og realistiske eksempler.

Frå resultata i denne oppgåva har det blitt vist at den utvikla metodikken vellykka finn mengda reserver som kan leverast, og produserer realistiske resultat. Resultata frå analysen er derfor verdifulle i seg sjølv, sidan dei illustrerer viktige konsept for marknadsaktørar som leverer balansetenester. Det har blitt vist at kostnaden og mengda reserver som kan leverast frå eit vasskraftsystem i regulerkraftopsjonsmarknaden er sterkt knytt til mengda vatn som er tilgjengelig i systemet sine magasin. I tillegg speler systemet sin fleksibilitet ei viktig rolle, då meir reserver kan leverast frå eit system med færre restriksjonar knytt til vassvegar og magasin. Sidan meir fleksibilitet er tilgjengeleg om reserver vert levert frå eit system som består av fleire kraftstasjonar, kan meir reserver typisk leverast frå denne typen system, til ein lågare kostnad.

Analysen har blitt gjennomført i fleire steg. Først har det forventa talet timar der den reserverte kapasiteten blir aktivert i ei veke blitt funne. Dette er estimert basert på tilgjengelig historisk data for det nordiske kraftsystemet, og statistiske metodar har blitt brukt til å finne det forventa talet. Vidare har den maksimale mengda kapasitet som kan bli aktivert gjennom den forventa tidsperioden utan å tømme magasina i systemet blitt funne. Til slutt har kostnaden av å levere ulike mengder reserver blitt funne. Analysen har blitt utført på to ulike vasskraftsystem, der ulike mengder produksjonskapasitet har blitt reservert til regulerkraftopsjonsmarknaden, og mengda tilgjengelig vatn i magasina til systema har blitt variert.

Til slutt har det blitt vist at mengda reserver som faktisk kan leverast er avgrensa, sjølv om systemet lett kan holde av meir produksjonskapasitet frå generatorane. Dette er både på grunn av mangel på tilgjengelig vatn til å aktivere meir reserver, i tillegg til brot på hydrologiske restriksjonar. Derfor må dei eksisterande modellane utvidast med metodikkar av typen som er presentert i denne oppgåva for å få verktøy til beslutningsstøtte som er godt egna til å delta i fleire marknader.

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Acronyms

TSO Transmission System Operator

DAM Day-ahead Market

IDM Intra-day Market

FRC-N Frequency Controlled Reserves for Normal Operation

FRR-A Automatic Frequency Restoration Reserves

FRR-M Manual Frequency Restoration Reserves

RK Regulating Power Market

RKOM Regulating Power Option Market

Chapter 1

Introduction

This chapter will present some background material and define the scope of the problem addressed in this thesis.

1.1 Background

Traditionally, a lot of the electrical power generation in Europe has come from thermal generation. In a power system based on thermal generation, the energy is stored in the fuel and can be converted to electrical energy whenever needed. However, as there are a lot of emissions associated with a power system based on fossil fuels, this solution is not very sustainable. Therefore, an ambition of a power system based on renewable resources is being implemented worldwide. Among these policies, the 20-20-20 energy and climate targets have been set by the European Union[5].

Although renewable energy can be both clean and cost effective, one of its main drawbacks is that the power output is very weather dependent. Wind and solar power extract energy from natural forces in order to produce electrical power, which can be unreliable. Since the amount of power produced is dependent on the intensity of the weather dependent sources, the ability to regulate the power output is limited. Also, storing the energy from these sources is very costly, so the energy has to be used when it is produced. Because the power production from these sources may not always be sufficient, some kind of backup source is needed in order to provide enough energy to cover the demand at all times. Since the weather is changing swiftly, this backup source needs to be able to adapt quickly to deviations. Additionally, forecasting the exact time of the weather changes is close to impossible, adding a lot of uncertainty to when the backup source is needed.

A very well suited, renewable source for balancing power is hydro power. Since water is being stored in reservoirs, the energy can be produced whenever needed. Also, the power output can be adjusted very fast, and the most efficient operation point is usually around 90% of the units' maximum capacity. Hence, reserve capacity is already available when power is being produced at the best efficiency. Additionally, both the start up time and cost of hydro power are very low, easily making more capacity available whenever needed.

As stated by the Norwegian TSO, among others, more intermittent renewable energy such as wind and solar power is expected to enter the European power system. Additionally, climate change contributes to more extreme weather conditions, increasing the frequency of transmission and generation outages. Hence, the power supply becomes less reliable, and the need of balancing power is growing. As the Nordic power system is based on a lot of hydro power, it is well suited for delivering balancing services to the rest of the European power system. This solution would be beneficial for the hydro power producers, which could receive a higher price for the produced power through the balancing markets, as well as being a good alternative for the European system's need of balancing power[2].

1.2 Problem Formulation

The main task in the day-to-day scheduling for a hydro power producer is to decide how much the production of electrical energy should be in the coming hours. If the hydro system has the possibility to store water in reservoirs, the producer might gain higher profits by saving the water for later. But then there is also a chance of the reservoir filling up, causing the water to spill. As this water could have been used to produce electricity, the producer could have utilized the water better by producing more energy at lower prices. Therefore, finding the balance between producing now versus saving water is the key question in hydro power scheduling.

Most of the produced energy in the Nordic power system is sold in the day-ahead market, Elspot. As several markets has been developed for balancing the power supply and demand, selling power has become a more complex problem. Producers can choose to set aside capacity for the TSO to restore imbalances between supply and demand for a given period. This commitment can be made before the amount of energy which is sold in the day-ahead market is specified, but also after the energy is sold in the market. As many of these markets are relatively new and still under development, no commonly used method for finding the optimal volumes to offer in the different markets are established.

For the power producers to be able to maximize their profit, an optimization model is often used to find the volumes of sold energy in the power market which generates the most income. The short term optimization model SHOP is a well known model by Nordic hydro power producers. However, the model is only optimizing the volume to be sold in the spot market, and are not optimizing the amount of power to be sold in the reserve markets as well. As selling power in these markets generates income to producers in the same order as the day-ahead market, a higher combined revenue may be received when participating in several markets. Therefore, finding the volumes in the balancing markets which makes the highest total revenue from both the day-ahead market and the balancing markets is vital for the producers.

In SHOP, it is possible to allocate a specified amount of capacity to each of the different balancing markets, and then optimize the volume of energy sold in the spot market. By specifying an amount of capacity for the balancing markets, this capacity will then be unavailable in the spot market. Consequently, there are opportunity costs related to participating in the balancing markets, since the capacity held off for these markets could have been used to generate income in the spot market. As the opportunity costs of reserving capacity in the reserve markets decide the price of which the producer is willing to deliver balancing services at, finding these opportunity costs are essential when planning in several markets.

When making commitments in the balancing markets, the producer has to set her production plans in order to meet these obligations. "Water behind capacity" is a term that describes a specific challenge for hydro power producers who provides ancillary services to the power system through the balancing markets. When reserving capacity in these markets, the hydro power producer has to be sure that the reserved capacity can be activated without violating technical, hydrological or environmental constraints. Current decision support tools like SHOP, which provides optimal production plans for Nordic power producers, does not ensure that all constraints are held when reserves are activated in real-time. Hence, an important challenge is to verify the production plan so that the head dependent power output always can be adjusted in order to meet the commitments made in these markets. Therefore, the main objective in this thesis has been to address the limitations in the existing models, and to develop a methodology specifically to determine the amounts of reserves which can be delivered without violating any relevant constraints. This has been done using SHOP, with its newly developed simulation functionality. The second objective in this work has been to validate the methodology on illustrative and realistic case studies. Finally, the results have been further analysed in order to find strategies when planning in several markets.

1.3 Literature Survey

Several studies have been carried out for finding optimal strategies in both the day-ahead market and the balancing markets, using both deterministic and stochastic models. This thesis is based on the deterministic model which optimizes the profits in the day-ahead market described in [6]. Finding optimal strategies in the day-ahead market have also been done using stochastic optimization in [7], [8], and [9]. However, these studies do not include the balancing markets. In [10], [11] and [12] the opportunity costs of participating in the reserve energy market have been found, which make the basis of the bids in both the up regulating and down regulating markets. These studies use a similar approach for finding the opportunity costs as the approach presented in this project. Furthermore, [13] and [14] use a stochastic model to optimize the total revenues from both the day-ahead market and the reserve energy market. However, the change in water availability when reserves are activated are not included in any of these studies, neither is ramping constraints. These challenges are addressed in [15], and in [16] a stochastic model has been used to optimize the total revenue when participating in several markets, including the possibility of running out of water when reserves are activated.

Except of [13], all of these studies have only analysed the reserve energy market. In this market, the commitment is set for the next hour, and the volume can vary in each hour. Additionally, the power producer can decide which hours to bid in, as opposed to the regulating power option market where the commitments are made for all the hours during the day for a whole week. Hence, the power producer has a lower risk of running out of water when participating in the reserve energy market rather than the regulating power option market. Additionally, reserves can be delivered in both directions in the reserve energy market, which also lowers the risk of emptying the reservoir.

As stated earlier, the main objective in this work has been to address the problems regarding water availability and other hydrological constraints when activating reserves, and develop a methodology to find the amounts of reserves which can be delivered without violating these constraints. In order to avoid distortion from uncertainty and give clear and intuitive results, the methodology has been developed using deterministic optimization.

Finally, the thesis is partially based on the specialization project carried out by the author as part of the Master of Science degree, and repeats some of the theoretical concepts used the previous thesis. In the specialization project, the opportunity costs of withholding generation capacity for different types of reserves were found without considering activation.

Chapter 2

Theoretical concepts

This chapter will present some of the main concepts and market mechanisms of which the thesis is based on.

2.1 The Frequency in a Power System

In an electrical power system, it is required that the amount of produced and consumed electrical power is equal. Excess or lack of power in the system may result in unstable operations and undesired values of the voltages in the system[3]. For this reason, it is important that there is a balance between power production and consumption at all times. To mirror the state of the system, the system's electrical frequency is used as an indicator of whether the system is in balance or not. When the produced power equals the consumed power, no excess power is stored in the motors or generators in the system, resulting in a constant rotational speed. However, if there is a mismatch between electrical production and consumption, the difference in electrical power will be compensated through a change in the mechanical rotating energy. This change accelerates the generators and motors in the system, making them rotate at a different speed. Since the system frequency is dependent on the rotating speed of the generators, a change in the rotating speed will change the system frequency. On this basis, the system frequency is a measure of the power balance in the electrical system. From [17],the relation between the electrical frequency f_{se} and the rotor speed n_m for a single synchronous generator with P number of poles is given in equation (2.1).

$$f_{se} = \frac{n_m P}{120} \tag{2.1}$$

To maintain the system balance, detailed planning of the system is necessary. It is the job of the

TSO to make sure that the production and consumption of electrical power are the same at all times. To be able to do this, accurate forecasts of the power consumption are needed, and the consumption then has to be matched with the planned power generation. An efficient way to handle this is through a power market.

2.2 The Power Markets

In a power market with high liquidity, most of the power consumed is bought in the market. In the same matter, most of the power generated is sold in the market. The intention is that a balance in the market will lead to a physical balance in the power system. Thus, the participants in the market are planning their electrical power consumption and production based on their position in the market.

Elspot and Elbas

The spot market, also called Elspot or the day-ahead market is the main market for trading physical power. This is the market which makes the basis of the planned future power production and consumption[1]. The market is cleared for every hour for the next day, meaning that the market participants are trading power for every hour for the next day. Thus, the market participants will know the day ahead the price and volume of their power production and consumption for each hour of the next day. The producers are preparing bids of how much power they want to sell, and at what price. This gives the supply curve for each individual producer. All the selling bids are accumulated to one curve, giving the supply curve for the system[18]. The same goes for the consumers, which are preparing bids of how much power they want to buy to cover their needs, and at what price. As for the selling bids, the buying bids gives the relation between consumption and price, and are accumulated to the demand curve. The intersection point of these two curves gives the system price and volume. Given the system price, all the consumers and producers get an obligation to produce or consume a volume of power based on their bids. In this way, the produced and consumed power for every hour for the next day is planned in balance. Figure 2.1 gives a graphical view of the intersection of the supply and demand curves.

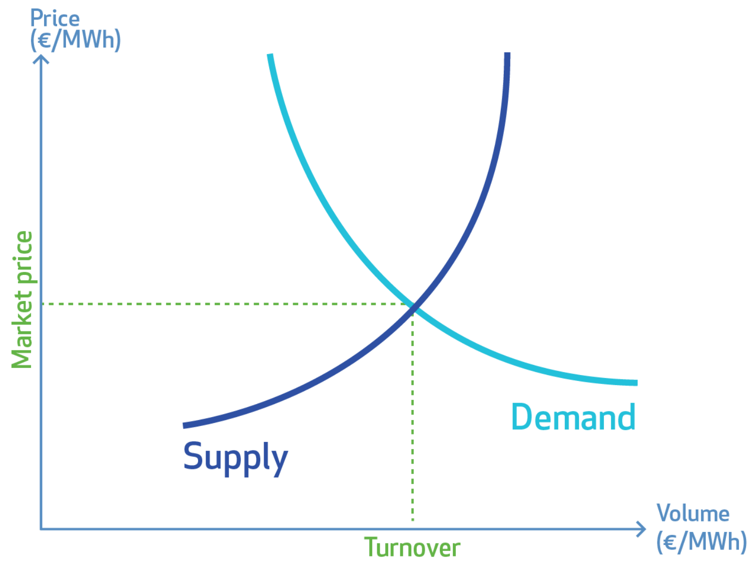

Figure 2.1: Supply and demand intersection point, taken from NordPoolSpot [1].

After the Elspot market is closed, the participants may not be able to deliver the committed volume or need a higher volume for consumption, due to reasons as unforeseen events, outages, unexpected weather conditions among others. Through the Elbas market, the market players get the opportunity to trade volumes after the Elspot market is closed. Thus, imbalances between the planned volume traded the day-ahead in the Elspot market, and the actual volume consumed or produced real-time can be corrected. This market opens after the Elspot market is cleared, and trades can be made up to one hour before real time. Hence, the Elbas market is often referred to as the intra-day market.

2.3 Balancing Markets

The need of reserves

Although the major part of balancing production and consumption is handled through the Elspot and Elbas markets, deviations still occur. Because these markets have a time resolution of one hour, production and consumption would have to be constant within a given hour to keep the system balance. In practice, this is not possible. The power consumption is varying continuously depending on the consumers' use of electricity. For power generation, the production from thermal- and hydropower can be set relatively constant. However, the power generation from renewable sources as solar and wind power depends on the intensity of wind and solar radiation. These intensities are varying within the hour, and forecasting these variations accurately is hard. In addition, the loss off major components such as generators and transmission lines results in deviations from the planned production and consumption[18]. These are all factors which may lead to system imbalance within the operation hour. To handle these imbalances, balancing services are needed to correct the mismatches.

For the Norwegian power system, there are three types of reserves: primary reserves, secondary reserves and tertiary reserves. Both the primary and the secondary reserves consist of capacity reserved from operating generators, and can therefore be activated quickly. This types of reserves are referred to as spinning reserves. The activation is done automatically, in contrast to tertiary reserves which are activated manually. In addition, the tertiary reserves do not have to be spinning, which results in a longer activation time[19].

When an imbalance takes place, the primary reserves will be activated instantly to correct the mismatch in power. To be able to handle new imbalances, the secondary reserve is activated in order to release the activated primary reserve. In the same manner, the tertiary reserve is activated in order to release the activated secondary reserve. Figure 2.2 gives an illustration of the power system's restoration scheme.

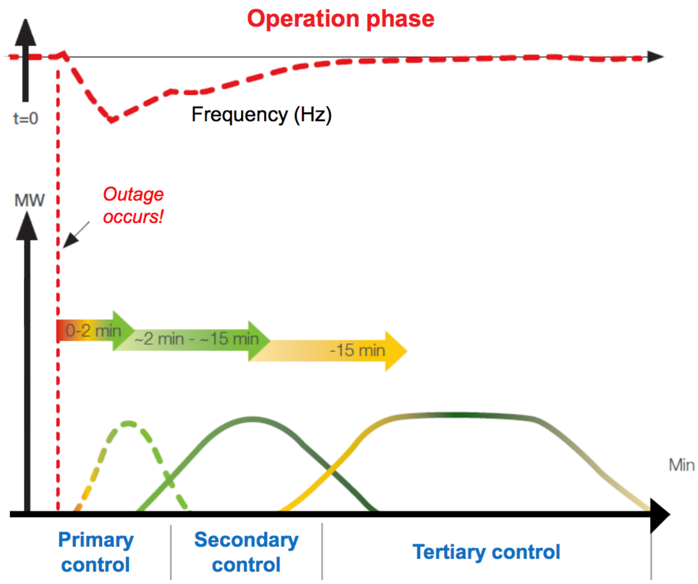

Figure 2.2: Reserves activation scheme, modified from Statnett [2].

Primary reserves

When an imbalance between production and consumption first happens, the synchronous frequency will change. To restore the imbalance, the primary reserves are firstly activated. These reserves consist of units already operating, so the response time is very short. The speed governor [1] of a generating unit senses the change in system frequency, and automatically changes the mechanical power input to the turbine through the main valve[3]. Hence, the electrical power output from the generator is adjusted to correct the system imbalance. Figure 2.3 illustrates a block-diagram of the control system related to the primary reserves. How much the speed governor should react to a disturbance is dependent on the droop setting[2] of the speed governor[20]. A high droop setting means that the output power is changed less for a given frequency deviation. Hence, the delivery of primary reserves for a certain deviation in frequency, for one specific generator, is set by the droop setting. In this way, all the generators participating in the primary reserves' market are contributing to restoring the system balance. For normal operation, the frequency band is set to 0.1 Hz, meaning the capacity reserved in the market is based on a dis-

[1] "The function of the speed governor is to monitor continuously the turbine-generator speed and to control the gate position which adjust flow into the turbine in response to changes in system frequency" [3]

[2] The droop setting of a generator gives the relation between the change in output power from the generator and the change in system frequency of the system.

turbance of 0.1 Hz. This capacity has to be available for both up and down regulation[21]. There is also a market for larger disturbances, but this will not be covered in this thesis. The market players get paid for the capacity reserved per hour. Extra energy delivered is also being compensated for. Reservation of capacity can both be made through the weekly or the daily market.

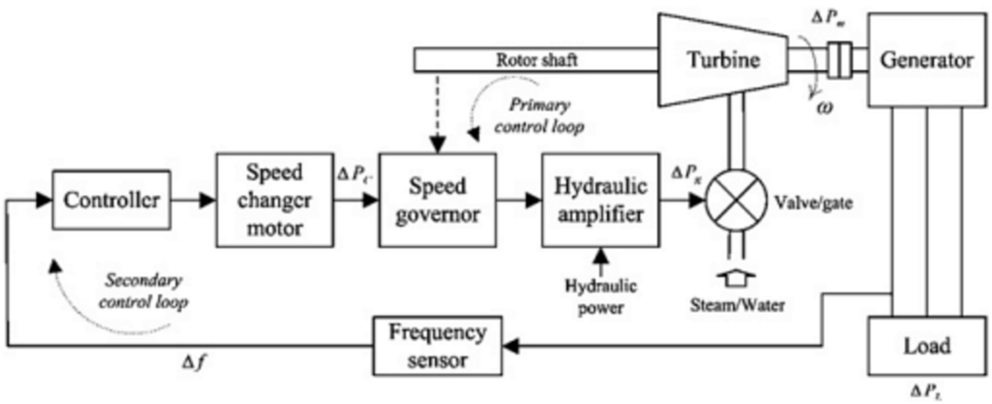

Figure 2.3: Primary reserves' control system, taken from Bevrani [3].

Secondary reserves

If the imbalance lasts for more than a few minutes, the secondary reserves are activated, releasing the primary reserves for new imbalances. The activation is done through the TSO's control system, adjusting the set points of the regulating generators. Hence, a direct connection between the TSO's control system and the regulating generators' control systems are necessary[18]. As with the primary reserves, the secondary reserves have to be spinning in order to be able to react quickly, and they are also activated automatically through the control system. The volume of reserved capacity is the amount of adjustments in the set points available for the TSO, and in contrast to the primary reserve markets, the capacity is either reserved for up or down regulation. The market players get paid for the capacity reserved for each hour, and the procurement is done through a weekly market. Extra energy delivered is also being compensated for. Which hours the weekly procurement is done for is varying, but the hours during the mornings and evenings are the most common[22]. This is the time of the day when the power production and consumption are the most variable, and the need for reserves is higher.

Tertiary reserves

If the imbalance still remains after the primary and secondary reserves have been activated for 15 minutes, the tertiary reserves are activated. Since the primary and secondary reserves are responding before the tertiary reserves, the response of the tertiary reserves do not have to be as fast as for the other types of reserves. Therefore, the tertiary reserves do not have to be spinning. The activation is done manually by the TSO, also in contrast to the other types of reserves which are activated automatically through the control systems.

The market participants place bids for letting the TSO change their planned production for given hours with the volume of the bids. Thus, the tertiary market is in fact an energy market, as the participants get paid for the extra energy produced per hour. Bids can be placed for both up and down regulation, and can be sent to the TSO up to 45 minutes before real-time. In Norway, this market is referred to as the reserve energy market, RK. Each of the market participants place their bids based on available volumes and costs, and the TSO activates the bids needed to regulate the power system according to merit order. Hence, the cheapest reserves are activated first, unless there are transmission bottlenecks between the area where the reserves are needed and the areas with the cheapest reserves. If there is insufficient transmission capacity, bids with higher prices are activated instead, in areas where there are sufficient transmission capacity to deliver the reserves to the areas where the reserves are needed [18].

Capacity can also be reserved in the tertiary market through the regulating power option market, RKOM. This market helps supply the system operator with sufficient capacity in the reserve energy market, and is at the time being mostly active during the high load winter season. However, the need for reserve capacity is expected increase in an integrated European power market with a higher share of intermittent renewable energy[12]. When reserving capacity in the RKOM market, the participants are obligated to place bids in the RK market at least the size of the reserved volume for all the respective hours. The market players gain a premium for reserving capacity in the RKOM market per hour. The procurement is done both through a weekly and a seasonal market. When reserving capacity in the weekly RKOM market, the capacity has to be available every day between 06.00 to 00.00 for the whole week [23]. At the time being, only reservation of capacity for up regulation can be made in the Norwegian RKOM market[23].

If a power producer has reserved more capacity than she can deliver based on the available water resources, actions has to be made in order to hold the balancing commitments made in the markets. First of all, when reserving capacity in the RKOM market, the participants are obligated to place bids in the RK market for every hour at least the size of the volume reserved in the RKOM market. It is through the RK market the capacity reserved in the RKOM market is activated, and the activation is done based on the merit order. The marginal costs of activating reserves from hydro systems, and thus the prices of the bids in the market, are dependent on the available water in the systems' reservoirs, or the filling ratio. If less water is available, the marginal cost of activation increases. As does the price of the bids in the RK market, and the reserves from the system are less likely to be activated, if other systems have lower marginal costs of activation. Therefore, if there are more available water at other hydro systems which deliver reserves, water unavailability may be avoided when the bid prices increase.

However, as both the energy produced in the spot market and in the RK market is produced from the hydro systems with the lowest marginal costs, and the marginal cost from a system is based on the water level in its reservoirs, it is likely that the reservoirs in different hydro systems somewhat have the same filling ratio. If a system's reservoirs have a higher filling ratio, the marginal cost of producing energy from this hydro system is lower. Due to the merit order, the hydro system will probably produce more energy than other systems with higher marginal costs, until the marginal costs at all the systems are equal. Therefore, if the marginal cost of activation is high at one hydro system, it is likely that the marginal costs of activation are high at other systems also. Hence, the chance of activation does not necessarily decrease as the marginal cost of activation increases, and there is still a chance of water unavailability. Additionally, the market participants are not allowed to price the obligated bids in the RK market high in order to avoid activation, when capacity is reserved in the RKOM market.

When capacity is reserved in the weekly RKOM market, a production plan for the whole week is typically made, and the obligations in the RKOM market are set. However, the obligation in the spot market are only made for the following day. Hence, the weekly production plan for the spot market, which are made when planning the RKOM commitments, can be seen as a strategy in the spot market the power producers try to follow in order to hold the reserves commitments. Hence, the weekly production plan in the spot market is not a committed production plan. Therefore, if there is a chance of water unavailability due to activation of reserves, less energy can be sold in the spot market than planned, in order to save more water for later activations. However, this restriction may force the producers to generate less energy in the spot market when the prices are high. Hence, too high commitments in the RKOM market may result in a lower total income. For these reasons, it is of much interest for the power producers to verify the amounts of reserves which can be delivered when making commitments in the RKOM market.

2.4 Planning Hierarchy and Models

As stated earlier, the main objective for a hydro power producer is to utilize the water in a way that maximizes her total profits. In order to do so, a production plan for the day-ahead has to be made, stating how much power that is to be produced in every hour for the next day. However, deciding the power production in a given hour is a very complex problem. On the one hand, producing power generates income by selling electricity. On the other hand, by not producing power, the water is available for power production in the future when the price may be higher. By calculating the value of storing water in the reservoir, a basis of deciding the production in a given hour can be made. However, since this value depends on many factors, with a long time horizon and much uncertainty, this calculation is not straightforward. To be able to solve the problem, the process has to be divided in different stages with different levels of detail, uncertainty and time resolution. The different stages are shown in figure 2.4.

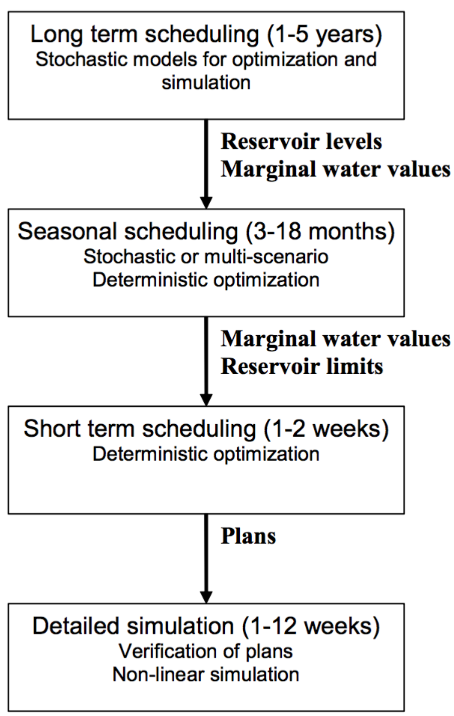

Figure 2.4: Hydro power scheduling stages, taken from Doorman [4].

Long term scheduling

Because some of the largest reservoirs may take years to fill up once empty, short term decisions may have an impact several years ahead. It is therefore necessary to have a long term strategy based on load, market prices and inflow. These are all stochastic variables, and a long time horizon means more uncertainty. In addition, the modeled hydro system often consists of several hydraulically coupled reservoirs, where the water level in one of the reservoirs is dependent on the use of water in the other reservoirs. To be able to solve these models, taking the uncertainty into account, a significant aggregation of the hydro system has to be made. All the reservoirs and power stations in the system are aggregated into one reservoir and one power station, to be able to compute the expected value of having water stored in the aggregated reservoir. This expected value is known as the water value, and is describing the long term strategy[4].

Seasonal scheduling

The main objective of the seasonal scheduling is to make a coupling between the long and short term scheduling. As the long term scheduling has to account for a lot of uncertainty, the level of detail has to be limited in order to be able to solve the model. However, in order do make short term decisions on whether to produce or not, the specific water values for each reservoir have to be known. These values are found in the seasonal scheduling, where the aggregated water values from the long term scheduling are used as input, and the individual water values for every reservoir are being calculated. Since the time horizon for the seasonal scheduling is shorter than for the long term scheduling, a more simplified description of the uncertainty can be made, making it possible to have a more detailed description of the hydro system topology. Besides, the seasonal scheduling models should have similar topology descriptions as the short term models in order to obtain proper boundary conditions for the short term scheduling[11].

Short term scheduling

In the short term scheduling, the actual hydro power production plan for the next hours and days is established. As the level of detail is very high when finding the optimal production plan, the time horizon and the level of uncertainty has to be limited in order to be able to solve the problem efficiently.

For the power producers to be able to know how much energy to sell in the power markets, the price of electricity has to be compared with the water value. Additionally, if reserves are to be delivered, this makes a great impact on the profit in the spot market. This is because less capacity is available for producing energy in the spot market when the capacity is reserved for balancing services. Besides, the generating units may have to be started mored frequently in order to deliver reserves, which results in higher start up costs. Hence, it may be profitable to produce energy for a few hours at low prices, instead of stopping and starting the generators. As the power production has to be planned for every hour of the day, planning the short term power production is a challenging task.

As already mentioned, SINTEF Energy Research has developed the short term optimization model SHOP to support power producers in preparing bids in the power market and establishing optimal production plans[24]. It is based on deterministic optimization, meaning that the input values are given as one scenario, without uncertainty. This is a simplification made in order to solve the problem more efficiently. Since the uncertainties in the price and inflow predictions are moderate in the short term horizon, the deterministic model is reasonable in spite of this simplification. Besides, scenario analysis can be carried out in order to determine the solution space for a longer time horizon[4].

Because the amount of energy which can be produced from a given amount of water is dependent on a large amount of physical factors, a very detailed description of the hydro system is needed in order to find the optimal production plan[11]. These factors consist of non-linearities such as turbine and generator efficiency curves and head losses, in addition to state dependencies, environmental constraints and more. Solving problems with state- or non-linear dependencies are difficult in terms of computation time for practical sized models[6]. Hence, for the model to be able to take into account all of the relevant physical factors and constraints when establishing the optimal production plan in the day-ahead market, successive linear programming is used to solve the problem efficiently. Hence, non-linearities are represented using step-wise linear curves. Additionally, the model uses the water values from the long and seasonal scheduling in order to determine the costs on the use of resources, and hence the amount of water stored in the reservoirs at the end of the period[25].

A simplified model describing some of the main concepts and complexities related to deterministic short term optimization models of hydro power production, including SHOP, has been made for this thesis in equations (2.2) - (2.2). It is partly based on the area optimization model presented in Doorman [4], in addition to Fosso and Belnes [6]. In this model, only one reservoir and generator are included, and the model is not considering all the physical relations which are accounted for in a more detailed model like SHOP.

$$\max \sum_{n\in N} p_n \cdot E_n + \alpha \cdot V_{|N|} - c^{start} \cdot \beta_n^{start} \tag{2.2}$$

s.t

$$E_n = \rho \cdot g \cdot (H_n - H_n^{loss}) \cdot \eta_n^{turbine} \cdot \eta_n^{generator} \cdot Q_n^D, \qquad n \in N \tag{2.3}$$

$$V_n = V_{n-1} + Q_n^I - Q_n^D - Q_n^E \qquad n \in N \tag{2.4}$$

$$|Q_n^D - Q_{n-1}^D| \leq R^{max} \tag{2.5}$$

$$V^{min} \leq V_n \leq V^{max} \qquad n \in N \tag{2.6}$$

$$E_n \leq \beta_n^{run} \cdot E^{max} \tag{2.7}$$

$$\beta_n^{run} \cdot E^{min} \leq E_n \leq E^{max} \qquad n \in N \tag{2.8}$$

$$\beta_n^{run} - \beta_{n-1}^{run} \leq \beta_n^{start} \tag{2.9}$$

$$\beta_n^{run} \cdot Q^{D,min} \leq Q_n^D \leq D^{D,max} \qquad n \in N \tag{2.10}$$

$$Q^{E,min} \leq Q_n^E \qquad n \in N \tag{2.11}$$

$$E^{max} - E_n \geq B_n \qquad n \in N \tag{2.12}$$

A summary of the notation used is given below:

N	number of hours in the planning period
p_n	spot price in hour n
E_n	produced energy in hour n
α	water value, which is dependent on the reservoir level $V_{\lvert N \rvert}$ at the end of the period
V_n	reservoir level in hour n
c^{start}	start up cost
β_n^{start}	decision variable if the plant is starting or not in hour n
β_n^{run}	decision variable if the plant is running or not in hour n
ρ	density of water
g	gravitational acceleration
H_n	plant head in hour n, dependent on V_n
H_n^{loss}	head loss in hour n, which is dependent on the discharge Q_n^D
$\eta_n^{turbine}$	turbine efficiency in hour n, which is dependent on the discharge Q_n^D
$\eta_n^{generator}$	generator efficiency in hour n, which is dependent on the produced energy E_n
Q_n^D	discharge to turbine in hour n
$Q^{D,min}$	min discharge to the turbine
$Q^{D,max}$	max discharge to the turbine
Q_n^I	inflow to the reservoir in hour n
Q_n^E	environmental bypass in hour n
$Q^{E,min}$	min environmental bypass
E^{min}	min generation capacity

E^{max} max generation capacity

R^{max} max ramping

B_n reserve requirement in hour n

The objective function given in equation (2.2) is to maximize the income from power generated and the value of the water left in the reservoir, less the start-up costs. Restriction (2.3) couples the turbine discharge to the energy output, and the restrictions (2.5) and (2.10) set the limits for the turbine discharge and ramping. A binary variable is set to one if the generator is running in restriction (2.7). Equation (2.4) handles the reservoir balance, and (2.11) sets the lower limit for environmental bypass. The restrictions (2.6) constrains the reservoir levels, and (2.8) covers the upper and lower generation capacity limits if the unit is running. When reserves is delivered from the generators, the upper and lower generation capacity is constrained by restriction (2.12). Note that only non-spinning reserves are included in the model. Additionally, the start up costs are added to the objective function using a binary variable when the generators are started in restriction (2.9). In a complete model, the dependencies of the variables H_n^{loss}, $\eta_n^{turbine}$,$\eta_n^{generator}$ would all be described by non-linearities.

Simulation

Even though the optimal solution has been found in the short term scheduling, it is not certain that the solution is in fact feasible. Even as a high level of detail has been used, the solution may not be within the acceptable limits. This is because the optimization model searches for the best decision in all of the time steps, based on the decisions in all of the other time steps. In order to do this efficiently, the optimization model uses successive linear programming where the non-linear dependencies are estimated using step-vice linear functions, which may not be precise. Furthermore, the optimization model focuses on finding the optimal decisions on the amount of power to be produced, but it may not find the corresponding water consumption and the hydro systems' reservoir levels in all of the time steps precisely. However, when all of the decisions have been made, accurate calculations of all the physical relations based on the decisions can be made, and the solution found in the optimization model can be verified. This can be done with a simulation model, where the true non-linear functions can be used in the calculations. Additionally, the decisions made by the optimization model can easily be modified and re-verified by the user in the simulation model[4].

In order to be able to verify and modify the solution found in SHOP, SINTEF Energy research has developed a simulation functionality for the model. The purpose of this functionality is "to return the physical response of the system given all user-controllable decisions as input"[26]. Hence, the SHOP simulator takes all the decisions made by SHOP as input, and finds if any of the decisions lead to situations that are physically infeasible. As this functionality was implemented very recently, there are very few references available which describes the mathematical modeling of the simulation functionality in SHOP.

Chapter 3

Methodology

This chapter will present how the analysis has been carried out, and includes the assumptions and simplifications that are made. Also, the hydro systems used in the case studies are presented.

3.1 Analysis Approach

When a power producer reserves capacity in the primary or secondary reserves' markets, the reserved capacity is usually activated for only a few minutes at a time. Consequently, the change in the plant discharge in order to regulate the power output is not present for a long enough period of time to significantly change the plants' reservoir level. Additionally, the reserved capacity is available for both up and down regulation, and the expected mean values of regulation in both directions are equal. Hence, water unavailability is usually not a problem when the reserved capacity are needed for activation. However, constraints regarding ramping or flow can still be violated during a short lasting activation.

In the tertiary reserves' markets, the reserved capacity is activated for a longer period of time. Often, the reserved capacity is activated for several hours at a time. Additionally, if the capacity reserved in the markets is only used for regulation in one direction, the change in plant discharge could be present long enough to significantly change the reservoir levels from the original plans. Hence, high amounts of reserved capacity from hydro systems with small reservoirs could lead to water unavailability in periods when the power system needs more regulation. Additionally, the ramping and flow constraints are present to the same extent as with the other balancing markets. Therefore, the methodology presented covers all the different balancing markets, although the methodology is only applied on case studies regarding the regulating power option market in this thesis.

In order to easily address the limitations in the existing models, the very same models have been used in the methodology. Therefore, the methodology is based on SHOP, with its newly developed simulation functionality. In order to obtain adequate decisions in the balancing markets, the usage of the model functionalities have been modified in innovative ways to verify sufficient water availability and feasible decisions in the balancing markets. The methodology both utilizes the optimization functionality in SHOP, as well as the simulation functionality in verifying the production plans obtained. Furthermore, the analysis has been carried out with a price taking hydro power producer's point of view, both in the spot market and the RK market. Additionally, the balancing products that are assessed correspond to the current definitions set by the Norwegian TSO.

Step One: Finding the Expected Amount of Time With Activation

The first step in the methodology is to find the expected number of hours the power system needs up regulation. In order to do this, available historical data of the Nordic power system is collected, and the number of hours with up regulation is counted for every week in the available data. Based on this count, the mean value and standard deviation of the number of hours with up regulation within a week is found. When the mean value and standard deviation is found, a normal distribution is assumed in order to find the probability of a given number of hours with up regulation within a week. Even though the number of hours with activation is not normally distributed in reality, this assumption is made in order to generate illustrative and intuitive results. With the normal distribution, different risk levels are set for the maximum number of hours' regulation is needed. Using the risk levels, from now on denoted r, the number of hours corresponding to the probability of having a higher number of hours with activation is found using the normal distribution. This is illustrated in figure 3.1 below.

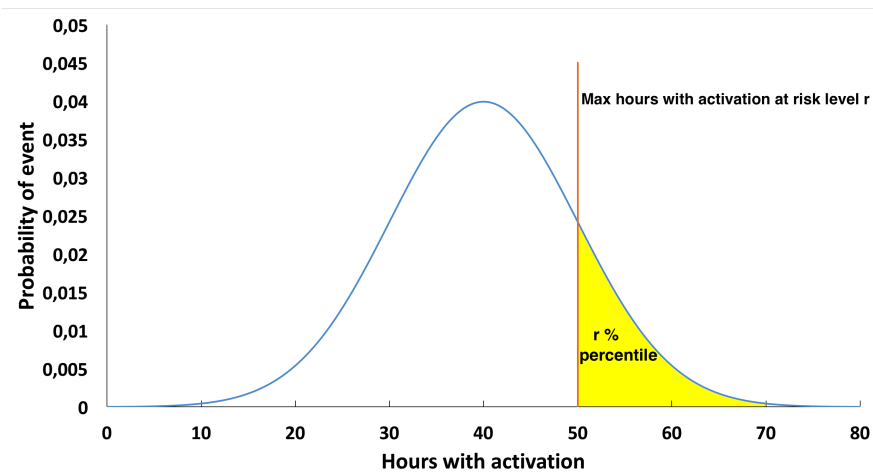

Figure 3.1: Illustration of risk level

Furthermore, it is unlikely that the reserved capacity from a certain hydro system is activated every time the power system is in unbalance. This is because there is usually more reserved power than what is needed, and the cheapest hydro systems to activate are used by the TSO. As the price of the bids in the RK market are dependent on many factors, for instance water values, production plans and reservoir levels, it is variable which hydro systems are the cheapest. Therefore, different rates of how often the reserved capacity from a hydro system contributes to up regulation when the power system is in unbalance are used in the analysis. For each of these rates, from now on denoted n, the maximum number of hours' which up regulation is needed, for different risk levels r, is found. Furthermore, the rate of activation is very dependent on the marginal cost of activating reserves from a hydro system, as more capacity is typically activated from systems with lower costs. The rate of activation is also depending on the transmission capacity in the area the hydro system is located in, as the reserved capacity is not activated if there is a grid bottleneck between the hydro system and the area where the reserves are needed. As it is hard to estimate the rate of activation without statistical data on how often a specific plant is activated, the analysis has been carried out using two different rates, 50% and 100%. Even as these values are probably too high, the analysis would be carried out in the same way using the real rates of activation. Besides, the limitations regarding water unavailability are addressed more clearly using higher rates.

In this work, a simplification has also been made so that the reserved capacity is only activated in the same price zone as the hydro system is located in. In reality, the reserves can also be used in other price zones, when there is sufficient transmission capacity between the zones. If there are bottlenecks in the grid, more expensive reserves could be activated by the TSO in order to supply the reserves where it is needed. As this may result in some areas being more favorable than others for delivering reserves, the rate of activation n may be different based on transmission capacity. To overcome this problem, power system data from only one price zone is used in the analysis, and the same rates of activation are used for all the hydro systems analysed. If the transmission capacity where to be included, the data would be collected from the entire Nordic power system, and different rates of activation would have to be estimated.

As the amount of activated reserves which is needed in two areas are dependent on each other, and a normal distribution requires independent stochastic variables, the data has to be either collected from only one zone or from the entire power system. Therefore, data from the same price zone has been used on all the hydro systems analysed, although the hydro systems are in reality located in different price zones. This is in order to compare the costs of delivering reserves from hydro systems with different features in terms of system characteristics, not from different areas.

Step Two: Finding the Maximum Amount of Delivered Reserves

The next step in the methodology is to find the maximum amount of reserves which can be delivered for a given number of hours with activation during the planning period. This is done for various amounts of reserved capacity, up to the point where more reserved capacity would lower the total production in the spot market significantly, and change the water availability.

When only participating in the day-ahead market, the reservoirs' flexibility is often maximally utilized, and the reservoirs may be emptied during the planning period before a large inflow or when the prices are high. Thus, there are no water available for activating reserves at this time. Additionally, the time of activation is unknown during operation, so it is not known when the extra water is needed. Besides, time delays in the water ways could make it hard to route extra water from one reservoir in the hydro system to another. In order to have water available for activating reserves, various constraints on water levels are therefore added. On the one side, a restriction on the water level limits the flexibility in the spot market, increasing the total opportunity costs. On the other side, a constrained water level makes more water available for activating reserves, and more reserves can be delivered. Thus, the total opportunity costs of delivering reserves are divided by a higher amount of capacity when finding the cost per MW of delivering reserves. In order to study this balance, various restrictions on the water levels in the reservoirs have been included in the analysis, and the volumes and costs of delivering reserves have been found for each amount of available water.

If a hydro system contains ramping restrictions, the system may not be able to activate all of the capacity which is reserved from the hydro system's generators without violating the ramping constraints. Additionally, the system may not be able to activate all the reserved capacity in all of the given hours, if the system's reservoirs are emptied while producing the extra amount of energy. The first step in finding the maximum amount of capacity which can be delivered for a given number of hours with activation, is to withhold a certain amount of capacity from the hydro system's generators in SHOP. If there are several generators in the hydro system, the reserved capacity is distributed over the different generators at the lowest total costs in SHOP. In order to do this, the sum of all the reserved capacity from each generator in the hydro system is set equal to the total amount of withheld capacity, and the optimal production plan in the spot market is then found in SHOP.

After the reserved capacity is distributed, the amount of capacity which actually can be activated for the given number of hours is found, using the same production plan. First, a very small amount of capacity is activated. If there are several generators in the hydro system, a load is added in the given hours the size of the amount of activated reserves greater than the original production. In this way, SHOP optimizes how the activated capacity should be distributed over the different generators in order to avoid penalties in the objective function. As violating constraints results in large penalties, SHOP tries to distribute the activation in every possible way in order to not violate any constraints. Hence, if a constraint is violated, there are no other possible way to activate the given amount of capacity without violating the constraint.

After the activation is distributed using SHOP, the solution is verified using the SHOP simulator. In the verification, accurate calculations are done using the simulation functionality in order to check if the solution empties the reservoir or violates the other constraints regarding ramping or flow. If the solution does not violate any of these constraints, the process is repeated with a larger amount of activated capacity until any of the constraints are violated. When the capacity is increased up to the point where a constraint is violated, the previous amount of capacity which did not violate the constraints represents the maximum amount of capacity which can be delivered for the given number of hours. This is done for every expected number of hours with activation, in order to obtain the relation between maximum activated capacity and the number of hours with activation. As stated earlier, the relation is found for different amounts of reserved capacity, and the hours with activation within the planning period is picked randomly. A flow chart illustrating the whole process is given in figure 3.2.

Additionally, applying different strategies for the distribution of the reserved capacity over the hydro system's generators has been investigated. For a simple hydro system with only one plant, all the capacity has to be reserved from this plant, and there is no need for distributing the reserves over other plants. If the system consists of several plants, the capacity is distributed at the lowest total costs in SHOP. However, the capacity can also be distributed at a fixed rate between each of the plants' share of the total capacity. In doing this, the effect of having more water available in certain parts of the hydro system has been studied. The costs and amounts of reserves which can be delivered have then been compared for the different strategies.

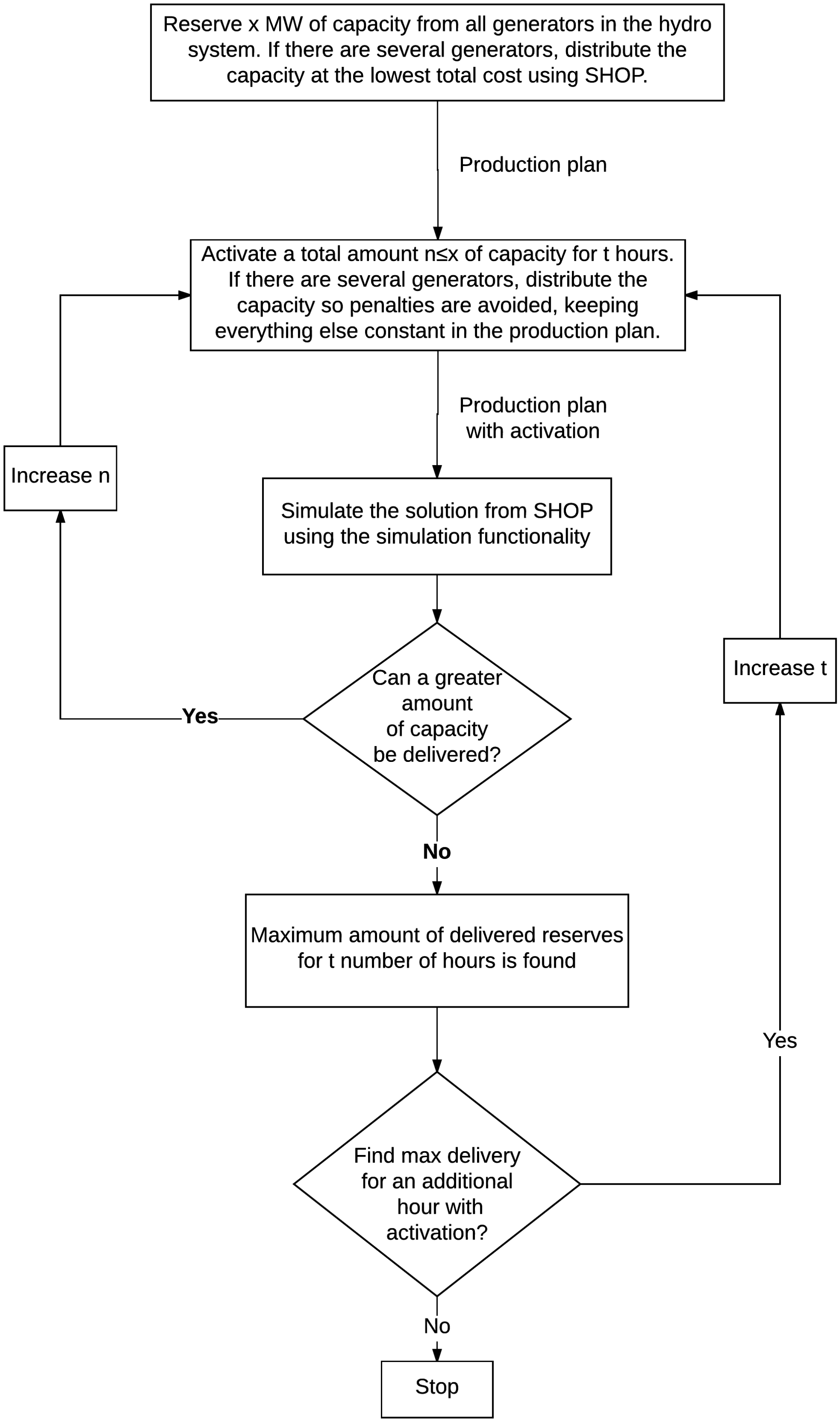

Figure 3.2: Finding max delivery process

Step three: Finding the Costs of Delivering Reserves

When combining the results from the first and the second step, the maximum amount of capacity which can be delivered in a week at given risk levels of violating the constraints is found in the final step. Additionally, given the maximum amount of capacity which can be delivered, the costs of delivering various amounts of capacity up to this level have been found. In order to do this, SHOP is firstly run without allocating any capacity to the RKOM market. This is in order to create a base case for the opportunity cost of participating in the balancing market. The objective function from SHOP gives the total revenue from the spot market and the value of the stored water in the reservoirs. When running SHOP with the reserve requirements, the income from the balancing markets are not included. Thus, when the objective function from the production plan which includes reserves is being compared with the objective function from the base-case, the total opportunity costs of delivering the given amount of reserves are found. For finding the cost of delivering the reserves per hour per MW, the total opportunity costs are divided by the number of hours the capacity is reserved for, as well as the amount of capacity which is delivered.

The costs of activating the reserves are assumed to be fully reflected through the mandatory bids in the RK market when participating in the RKOM market. Thus, the income from the RK market compensates for the start up costs, the potentially lower efficiency and the extra water which is being used when reserves are activated. Consequently, the costs of delivering capacity in the RKOM market are assumed to be solely based on the opportunity costs of having less available production capacity for the spot market.

3.2 Case Study

In this project, two different reservoir topologies with corresponding data have been used. These descriptions are based on real hydro systems, where only small modifications have been made in order to obtain case studies which suits the analysis well. These modifications are made as moderate as possible, in order to maintain authentic system descriptions. The two hydro systems are separated in terms of size, structure and complexity, and are located in two different regions in the Nordics. Even though the data of the two cases are collected from different regions, in two different years, the hydrological conditions and power demand is expected to be similar in both cases as they are both collected from the winter season. Hence, comparable market conditions are assumed. The zonal spot prices for the planning period in each of the cases are provided by the plant operator. These are presented using the historical spot prices from Nordpool[27], as the historical prices are public information. Since both cases are taking place during the winter, low temperatures contribute to a high demand for electricity. Besides, much of the precipitation falls as snow during the winter, resulting in a generally moderate inflow. Hence, the spot prices are commonly higher during the winter. Since the prices and inflow are deterministic when carrying out the analysis, perfect information about future inflow and prices is assumed. The inflow and water values are also provided by the plant operator, and the planning period is set to one week, since it is the resolution of the weekly RKOM market.

The first hydro system analysed is the Kvistforsen system, which is located in price zone SE2 in Skellefteå in Sweeden. This system is owned and operated by Statkraft, who has provided the data and authorised the system description used in SHOP. The main motive for studying this system is to address and consider the effects and limitations of delivering reserves from a system with ramping constraints. Consequently, the reservoir in this system contains a ramping constraint. The second hydro system analysed is part of the Røldal-Suldal system, which consists of the plants Kvanndal and Suldal 2, and is located in price zone NO2 in South-Western Norway. This system is owned and operated by Hydro Energy, who has provided the data and authorised the system description. This system does not contain ramping restrictions, but is a much more dynamic system than Kvistforsen. Hence, the main motive for studying this system is to investigate the possibility of water unavailability in different parts of a large cascaded system when participating in the balancing markets. Additionally, the effects of delivering reserves from several stations in the same hydro system have been compared with delivering reserves from only one station, with respect to the costs and amounts of reserves which can be delivered.

Kvistforsen

The Kvistforsen hydro system, which is illustrated in figure 3.3, consists of one power plant where the plant has two identical generating units. Each of the generating units has a production capacity between 16 and 72 MW. With two units, the total generation capacity of the plant is therefore between 16 and 144 MW, excluding losses. There is only one reservoir connected to the plant, where the reservoir head is regulated between 50.5 and 52 meters, giving a difference between maximum and minimum head of 1.5 meters. Maximum reservoir ramping is set to 5 cm per hour for this study. With maximum plant discharge and no inflow, the reservoir can be emptied from maximum level in about 10 hours. This means that the energy production in a week is very dependent on the inflow.

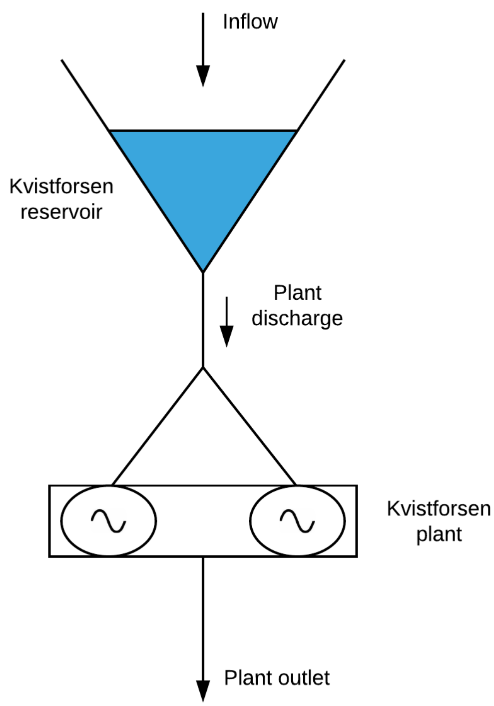

Figure 3.3: Kvistforsen hydro system

Additionally, the volume of the reservoir has been increased from the real system description up to 12 million m^3, in order to have a larger amount of water available for activating reserves. As the reservoir in the real system description is much smaller, water unavailability is in reality an even greater limitation when delivering reserves from the Kvistforsen hydro system than addressed in this thesis. The reason for the increase is to obtain a wider spread in the amounts of delivered reserves, which can be obtained when the maximum amount of reserves delivered is increased. When the amounts of verified reserves have a wider spread, the factors which affect the costs of delivering reserves are easier addressed.

As the plant generators have a wide operating range, the units are able to reserve a great amount of capacity in the RKOM market. However, both water availability and the ramping restriction greatly limit the amount of reserves which can be activated. Therefore, capacity from 20 to 40 MW, using a step of 5 MW has been reserved from the generators, and the amount of capacity which can be delivered at certain risk levels with the corresponding costs have been found. Furthermore, the planning period used for the Kvistforsen case takes place in the end of February, from the 21th to the 28th, 2016. The historical spot prices in SE2 are given in 3.4. The spot prices in the planning period are typical for the winter season, with a low inflow, and a steady price with some variations within a day. In two of the days, the price is substantially higher. This may be caused by a low temperature in these days, resulting in a higher demand of power used for heating.

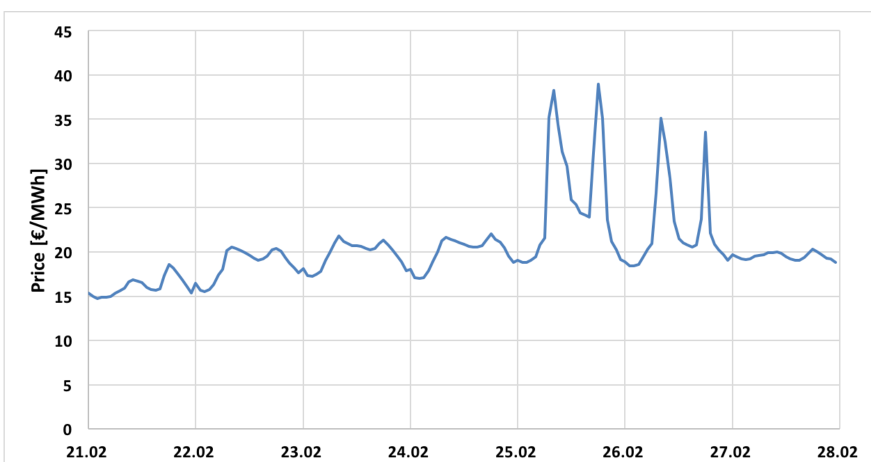

Figure 3.4: The spot price for the planning period

As water unavailability is a possibility when delivering reserves from Kvistforsen, the analysis has been carried out setting different restrictions on minimum reservoir levels in the production plans. Based on these minimum levels, different amounts of water are available for activating more reserves at different costs. Additionally, the maximum ramping restriction limits the amount of capacity which can be activated, and the analysis has been carried out while reserving different amounts of capacity from the generators at Kvistforsen plant.

Røldal-Suldal

The part of the Røldal-Suldal hydro system which have been analysed in this thesis includes the two power plants in the cascaded system illustrated in figure 3.5. The upper plant, Kvanndal, consists of one generating unit with a production capacity up to 42 MW, and the plant utilizes a head of about 300 meters. It is directly connected to one reservoir, Sandvatn, which again receives water from two other reservoirs, Holmevatn and Isvatn. Sandvatn has a volume of 66 million m^3, and Holmevatn and Isvatn has a volume of 96 and 16 million m^3 respectively. During maximum plant discharge and no inflow, Sandvatn can be emptied from maximum level in about 1150 hours, or 48 days. Additionally, almost twice the volume of Sandvatn can be stored in the two reservoirs above. Hence, Kvanndal has a very high availability of water, and the rate between reservoir capacity and maximum discharge is very high.

From Kvanndal, the water is routed to the smaller reservoir Kvanndalsfoss, which can store 1.6 million m^3 of water. Additionally, this is the reservoir of which the lower plant, Suldal 2, is connected to. In the actual system description, it is possible to route water directly from Sandvatn to Kvanndalsfoss, but this possibility is not included in this thesis. This is in order to address the limitations when delivering reserves from a cascaded system more clearly. With no production at Suldal 2, and full production at Kvanndal, the reservoir can be filled up from empty in about 28 hours. This means that the risk of spilling water is rather high, as the reservoir fills up quickly.

As mentioned, the lower plant Suldal 2 is connected to the reservoir Kvanndalsfoss. The plant consists of two slightly different generating units with production capacity up to 72 MW and 76 MW. The plant utilizes a head of about 550 meters, where the total generation capacity of the plant is 148 MW. Furthermore, with no production at Kvanndal and maximum production at Suldal 2, Kvanndalsfoss can be emptied from full in about 14 hours. Hence, the production at Suldal 2 is highly dependent on the inflow to Kvanndalsfoss, which again is the outlet from Kvanndal. Consequently, the production strategy at Suldal 2 is set by the production strategy at Kvanndal.

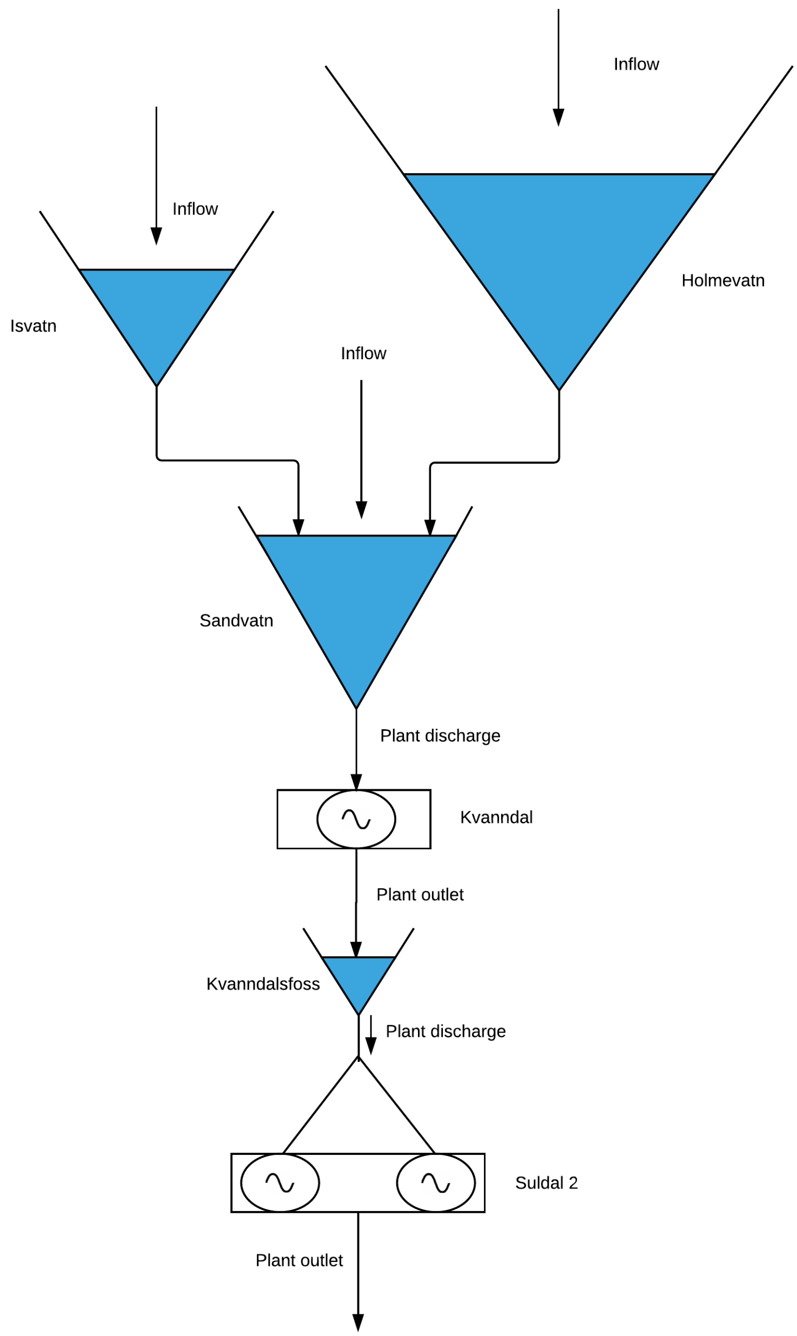

Figure 3.5: Røldal-Suldal hydro system

As with the generators at Kvistforsen, the generators at Suldal 2 and Kvanndal have a wide operating range, and the units are able to reserve a great amount of capacity in the RKOM market. However, there are no ramping constraints in any of the system's reservoirs. Additionally, as the reservoir between the two plants only holds a small volume, water unavailability becomes a larger problem in the Røldal-Suldal hydro system. This is amplified as the inflow to the reservoir, and hence the plant outlet from Kvanndal, is small compared to the plant discharge at Suldal 2. Besides, there is a possibility of spillage due to activation of reserves at Kvanndal. In order to isolate each of these events, the maximum amount of reserves which can be delivered has been found from each of the two plants separately. Next, these results are further used in analysing the amounts of reserves which can be delivered from both stations together. In each of the different cases, various amounts of capacity have been reserved from the hydro system's generators, and the maximum amounts of reserves which can be delivered have been found. The analysed period takes place between the 22th and the 28th of January, 2015, and the historical spot prices in NO2 are presented in figure 3.6. Again, the spot prices follow a pattern which is typical for the winter season in the Nordic power system.

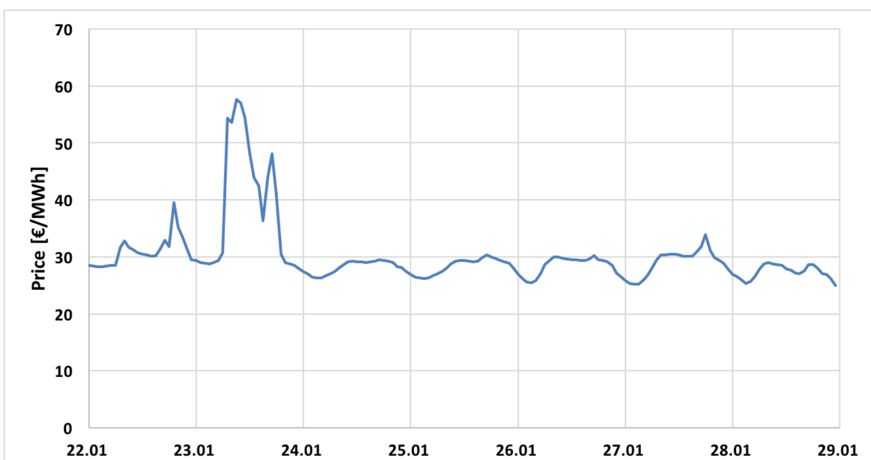

Figure 3.6: The spot price for the planning period

When reserves are delivered from Kvanndal, water unavailability is not really a problem as the reservoirs above are very large compared to the water usage at the plant. However, the extra water used at Kvanndal is let out in the small reservoir above Suldal 2. Hence, if the reservoir level is high, it is likely that the extra water used for activating reserves will spill, and the value of this water is lost. To avoid this, various restrictions on maximum reservoir level have been set for Kvanndalsfoss, and the volumes and costs of the delivered reserves have been found for the different constraints.

When the reserves are delivered from Suldal 2, water unavailability is the relevant constraint. This is also the case when the reserves are delivered from the whole hydro system, as the water usage at Suldal 2 is greater than the water usage at Kvanndal. Thus, both when the reserves are delivered from Suldal 2 and when the reserves are distributed over the two plants, various restrictions on minimum reservoir levels have been set for Kvanndalsfoss in the analysis. For each of these minimum reservoir levels, the amount and costs of the delivered reserves have been found.

Chapter 4

Results and Discussion

In this chapter, the results from the analysis will be presented, and the correlations between the different results are discussed.

4.1 Power System Statistics

When the number of hours with up regulation is collected from the available power system data, the normal distributions for the number of hours with activation of reserves, with the different rates of activation are made. As already mentioned, two different rates of activation have been applied. Both if the reserved capacity is activated every time the power system is in unbalance, corresponding to a value of n=100%, and if the reserved capacity is activated half of the time the power system is in unbalanced, corresponding to a value of n=50% have been applied. Based on the collected power system data, the mean value and the standard deviation of the number of hours with activation within a week with the different values of *n* are given in table 4.1. Both the normal distribution for n=50% and n=100% are presented in figure 4.1.

Value of n	**Mean**	**Standard Deviation**
100%	44.27	21.49
50%	22.14	10.47

Table 4.1: Mean values and standard deviations

From the results, it is rather intuitive that both the mean value and the standard deviation are half the value when the reserves are activated 50% of the time. Additionally, two different risk levels have been used for each rate of activation, both r=5% and r=1%. These risks correspond to the number of hours where the probability of the activation to be higher than the given value equals the risk, and are also presented in figure 4.1. Furthermore, the calculated values for the number of hours corresponding to the different risk levels are presented in table 4.2. Note that the value corresponding to a certain risk level when the reserves are activated half of the time is half the value of when the reserves are always activated.

Value of n	**Risk level**	**Maximum activation [hours]**
50%	**5%**	40
50%	**1%**	47
100%	**5%**	80
100%	**1%**	94

Table 4.2: Maximum activation at different risk levels

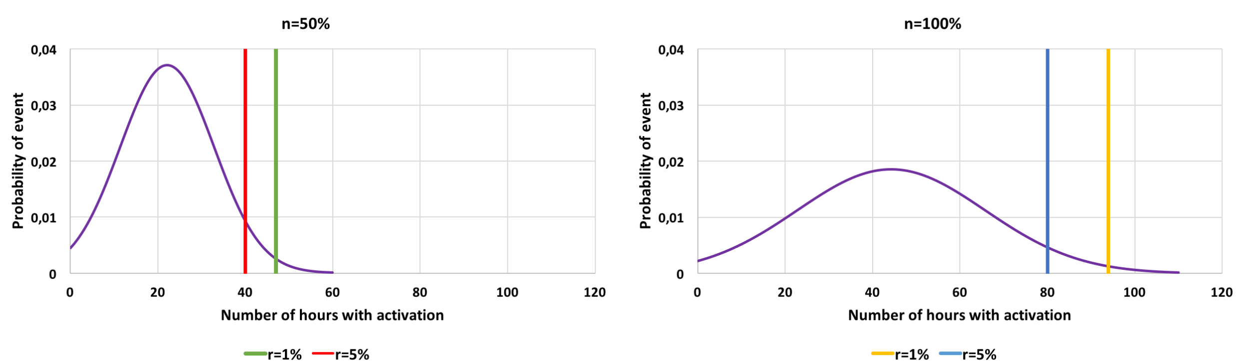

Figure 4.1: Corresponding risk levels

4.2 Kvistforsen

When reserves are to be delivered from Kvistforsen, a significant amount of water has to be held off the production plan in the spot market in order to have sufficient water to activate the reserves the required number of hours. Therefore, the analysis has been carried out requiring the water level in the reservoir never to fall below 8 million m^3, 10 million m^3 and 12 million m^3 in the production plan without activation. As the system's reservoir can store up to 12 million m^3, a large share of the reservoir's volume has been constrained, and less flexibility has been given in the spot market. For each of the volumes of water held off, the capacity which can be activated without violating constraints for a given number of hours is found, when different amounts of reserves are held off from the generators. These results are presented in figure 4.2.

From the results, it is clear that a very large amount of water has to be held off the production plan in order to be able to deliver reserves, if the reserves are activated whenever the power system is in unbalance. Additionally, the minimum amount of capacity which can be delivered in the RKOM market is 10 MW. Hence, if the maximum amount of capacity which can be activated from the hydro system is less than 10 MW, the system is not able to deliver any reserves in the RKOM market at all. This is the case when a low amount of water is held off the production plan and the reserves are often needed for activation. However, if the rate of activation is only 50%, more capacity can be delivered without emptying the reservoir. Although, the amount of reserves which can be delivered is much smaller than the amount capacity which is reserved from the system's generators. Hence, there is a big difference between the amount of capacity which is reserved in SHOP, and the amount of capacity which actually can be delivered. If 40 MW is reserved, only about 20-30 MW can be activated at the highest risk level and the lowest rate of activation due to water unavailability.

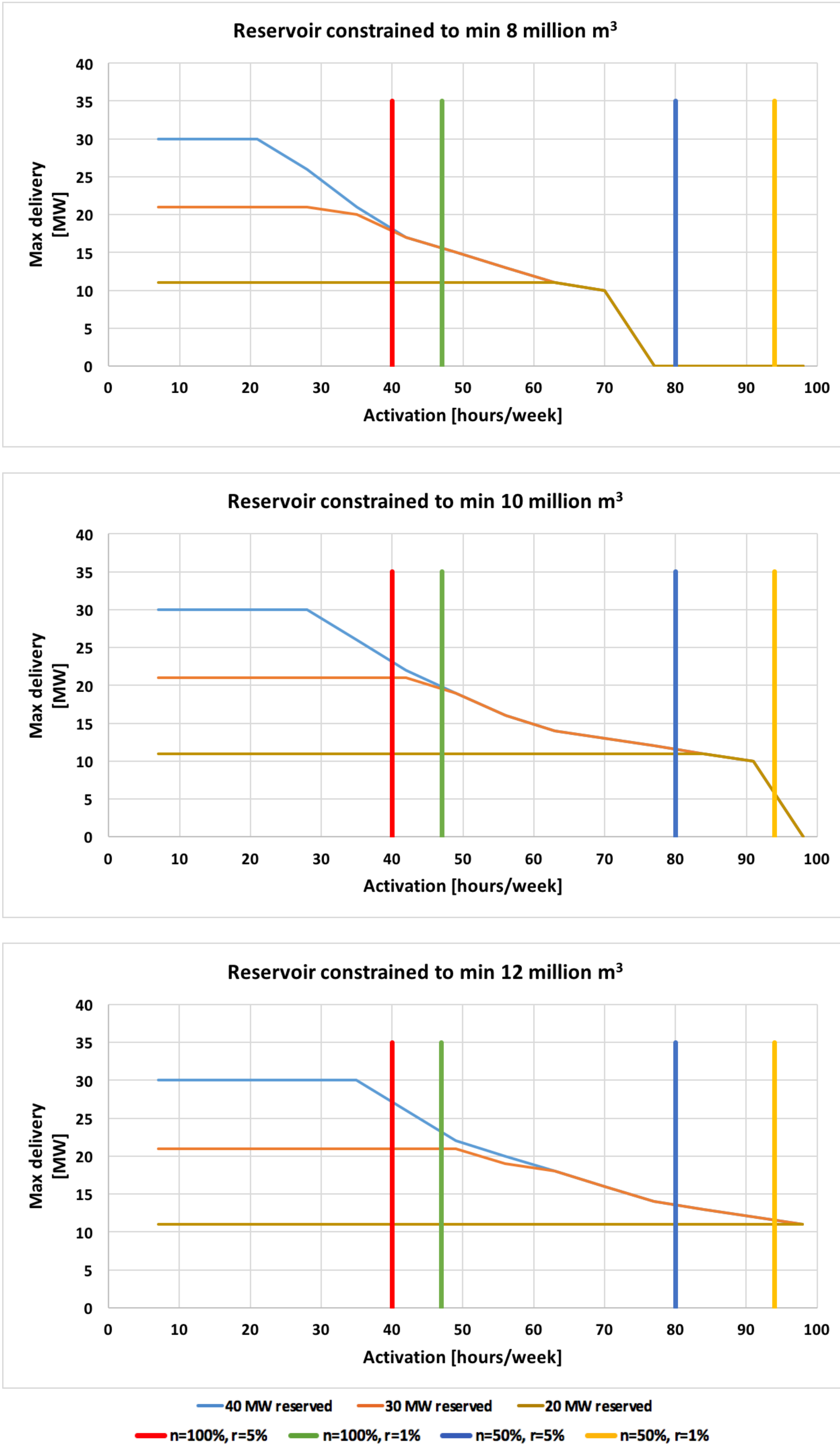

Figure 4.2: Delivered reserves from Kvistforsen

As the number of hours with activation decreases, the amount of capacity which can be activated before the reservoir is empty increases. This is because the water is distributed over fewer hours with activation. Additioanlly, if the maximum amount of activated reserves is reached because of water unavailability, an increase in reserved capacity from the generators does not increase the amount of reserves which can be activated. Hence, the amounts of delivered reserves are equal when different amounts of capacity has been reserved, as long as the amount of capacity which can be delivered is restricted due to water unavailability.

Furthermore, SHOP does not consider activation when the production plan is optimized for the given constraints. Therefore, the increase in the plant discharge when reserves are activated may violate hydrological constraints. For this reason, it is not possible to activate the total amount of reserved capacity from the generators at Kvistforsen, even if there is enough water available in the reservoir. This results in the horizontal sections in the graphs in figure 4.2, which illustrates that the delivered reserves are lower than the reserved capacity due to the ramping constraints, even if enough water is available for activation. As the plant discharge in the production plan decreases when more generation capacity is reserved, the plant discharge can be increased more before the ramping restriction is violated. Therefore, more reserves can be activated when more capacity is reserved. This can also be seen from the results, as the maximum deliverance of reserves are higher when more capacity is held off from the generators, and the activated reserves are not constrained due to water unavailability.

As constraining the reservoir's water level limits the production, and hence the income in the spot market, the costs of delivering reserves with different amounts of water withheld have also been analysed. This analysis has been carried out for the two risk levels, using a rate of activation of 50%. The results are presented in figure 4.3.

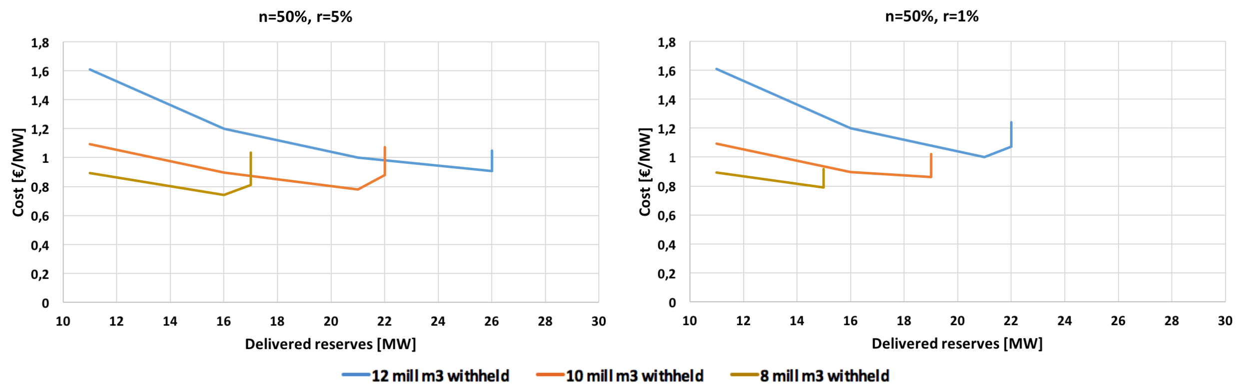

Figure 4.3: Costs of delivering reserves from Kvistforsen

When restricting the water levels in the production plan, higher total opportunity costs are obtained. However, the total opportunity costs are divided by the amount of delivered reserves in order to find the cost per MW. Therefore, the cost per MW is decreasing when more reserves are delivered for the same amount of water held off. As more capacity is held off the generators, less production capacity is available for the spot market. Since peak production often happens when the spot prices are high, limiting the production capacity decreases the production at high prices in the spot market. Therefore, the total opportunity costs are increased when more capacity is held off. However, the magnitude of the costs of withholding water is much higher. Even as the total costs are increasing when more reserves are delivered, the cost per MW is still decreasing as the total costs are divided by a larger amount of reserves.

Additionally, the generating units have the best efficiency around 90% of maximum production. Hence, the operating point does usually not exceed this point in the production plan, and around 10% of the production capacity can be reserved without significantly lowering the profits in the spot market. Hence, the costs per MW of delivering reserves are decreasing most rapidly up to this point, as the change in total opportunity costs when reserving more capacity is small, and the amount of delivered reserves is increased. When more capacity is reserved, the total opportunity costs increase more, and the cost per MW is decreasing less rapidly. This is the case up to the point where more reserved capacity from the generators does not contribute as much to a higher amount of delivered reserves because of water unavailability. At this point, reserving more capacity leads to higher total opportunity costs, but since the amount of delivered reserves increases less, the cost per MW of delivering reserves increases. When an increase in the reserved capacity does not contribute to an increase in the amount of delivered reserves at all, the maximum amount of delivered reserves is reached. At this point, reserving more capacity increases the total opportunity costs, but the amount of delivered reserves remains unchanged. This results in the vertical sections in the graphs of the costs of reserves per MW in figure 4.3. Note that the maximum amounts of delivered reserves in this figure are the same as the maximum amounts of delivered reserves in figure 4.2 for the same rates of activation, risk levels and water availabilities.

As the opportunity costs of withholding water are higher when more water is held off, the cost per MW of delivering the same amount of reserves is higher with a more strict restriction on the water consumption. Hence, it is not profitable to withhold more water than necessary for delivering the desirable amount of reserves. However, as more reserves can be delivered when more water is available, a high RKOM price could make it profitable to withhold more water to deliver more reserves. Finally, the maximum amounts of delivered reserves are dependent on the risk level. With lower risk levels, the expected number of hours with activation is lower. Hence, the available water are distributed over fewer hours, and the capacity which can be delivered is increased.

4.3 Røldal-Suldal

Delivering reserves from Suldal 2

As when reserves are delivered from Kvistforsen, water has to be held off the production plan in the spot market in order to be able to activate the reserved capacity from Suldal 2. Hence, the analysis has been carried out requiring the water level in Kvanndalsfoss never to fall below 0.6 million m^3, 0.8 million m^3 and 1 million m^3 in the production plan without activation. As the total volume of Kvanndalsfoss is 1.6 million m^3, a significant amount of water has to be held off the original production plan, making less water available for the spot market. For each of the minimum volumes of water stored in the reservoir, the amount capacity which can be activated without running out of water is found for different number of hours with activation, and different amounts of capacity reserved from the generators. The results are presented in figure 4.4.

From the results, it is clear that the lower amounts of reserved capacity from the generators can be delivered with only holding off a moderate amount of water, if the rate of activation is 50%. However, if the rate of activation is 100%, and the amount of reserved capacity is high, a significant amount of water has to be withheld in order to deliver an amount of reserves which is close to the amount of reserved capacity. Therefore, the amounts of reserves which can be delivered are smaller than the amounts of reserved capacity at higher rates of activation due to water unavailability. However, as there are no ramping restrictions in this hydro system, all the reserved capacity can be activated as long as there is enough water. Hence, when the rate of activation is 50%, the amount of capacity which can be delivered is close to the the reserved amount of capacity.

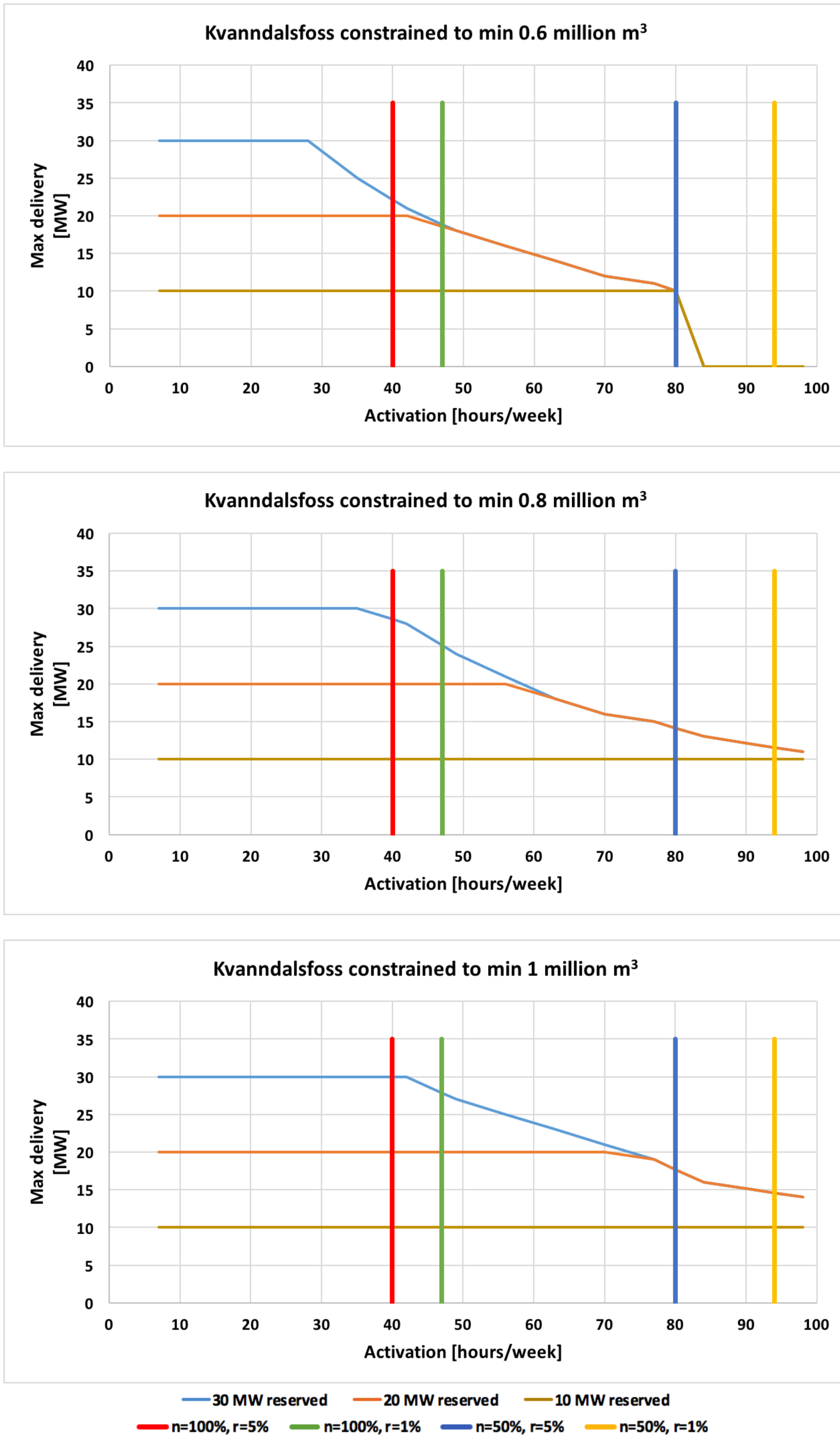

Figure 4.4: Delivered reserves from Suldal 2

As already mentioned, the flexibility in the spot market is reduced when more water is held off the production plan. Consequently, the profits in the spot market are also reduced, and the total opportunity costs of delivering reserves are increased. The costs per MW of delivering reserves for the different risk levels at n=50%, withholding different amounts of water are presented in figure 4.5.

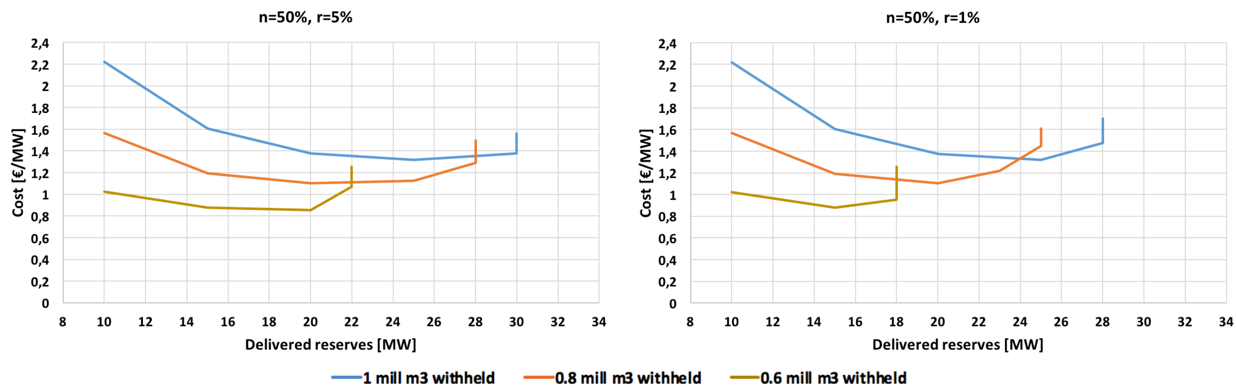

Figure 4.5: Costs of delivering reserves from Suldal 2

The costs of delivering reserves from Suldal 2 follow a similar pattern as the costs of delivering reserves from the Kvistforsen system. However, a higher share of the reserved capacity can be delivered from Suldal 2 than from Kvistforsen, and the benefits of reserving more capacity is better utilized. Additionally, the difference between the spot price and the water value affects the total opportunity costs. If the spot price is much higher than the water value, selling energy in the spot market is very profitable. In this case, reserving generation capacity in the balancing markets comes with a high opportunity cost. As the spot price in the Kvistforsen case is lower than in the Røldal-Suldal case, this is expected to contribute to lower opportunity costs of delivering reserves from Suldal 2. Furthermore, having restrictions on the water level in one reservoir also limits the flexibility at other plants in the hydro system. This may affect the opportunity costs at Suldal 2, but not at Kvistforsen. Additionally, which of the two hydro systems that generates the most income with less flexibility depends on many other factors beyond the ones already mentioned. Therefore, finding a clear pattern on why the costs of delivering reserves from Suldal 2 and Kvistforsen have similar magnitudes is not further analysed in this work.

Kvanndal

When delivering reserves from Kvanndal, the amount of water which is stored in Kvanndalsfoss has to be constrained in the production plan in order to avoid spillage when the reserves are activated. This is because the extra water which is used when the reserves are activated are accumulated in the reservoir. Since the production plan at Suldal 2 is already set when activating reserves at Kvanndal, Suldal 2 does not have the possibility to use the extra water accumulated in Kvanndalsfoss. Even though the hydro system is able to deliver more reserves when water is spilled, the value of the water is then lost. Hence, spilling water is treated in the same way as water unavailability, in order to avoid spillage when delivering reserves. Therefore, the analysis has been carried out requiring the water level in Kvanndalsfoss never to exceed 0.4 million m^3, 0.6 million m^3 and 0.8 million m^3. As the total volume of the reservoir is 1.6 million m^3, the amount of water which can be stored is greatly limited in the production plan, resulting in little flexibility in the spot market. For each of these constraints, the amounts of capacity which can be activated without spilling water are found for different number of hours with regulation, and different amounts of capacity reserved from the generators. These results are presented in figure 4.6.

From the results, one can see that the amounts of reserves which can be delivered for a high number of hours is limited. Hence, if the rate of activation is 100%, only small amounts of capacity can be delivered with low amounts of water stored in the reservoir. If more water is stored in the reservoir, no reserves can be delivered at all. However, if the number of hours with activation is lower, a moderate amount of capacity can be delivered. Therefore, the hydro system is able to deliver some reserves at lower rates of activation.

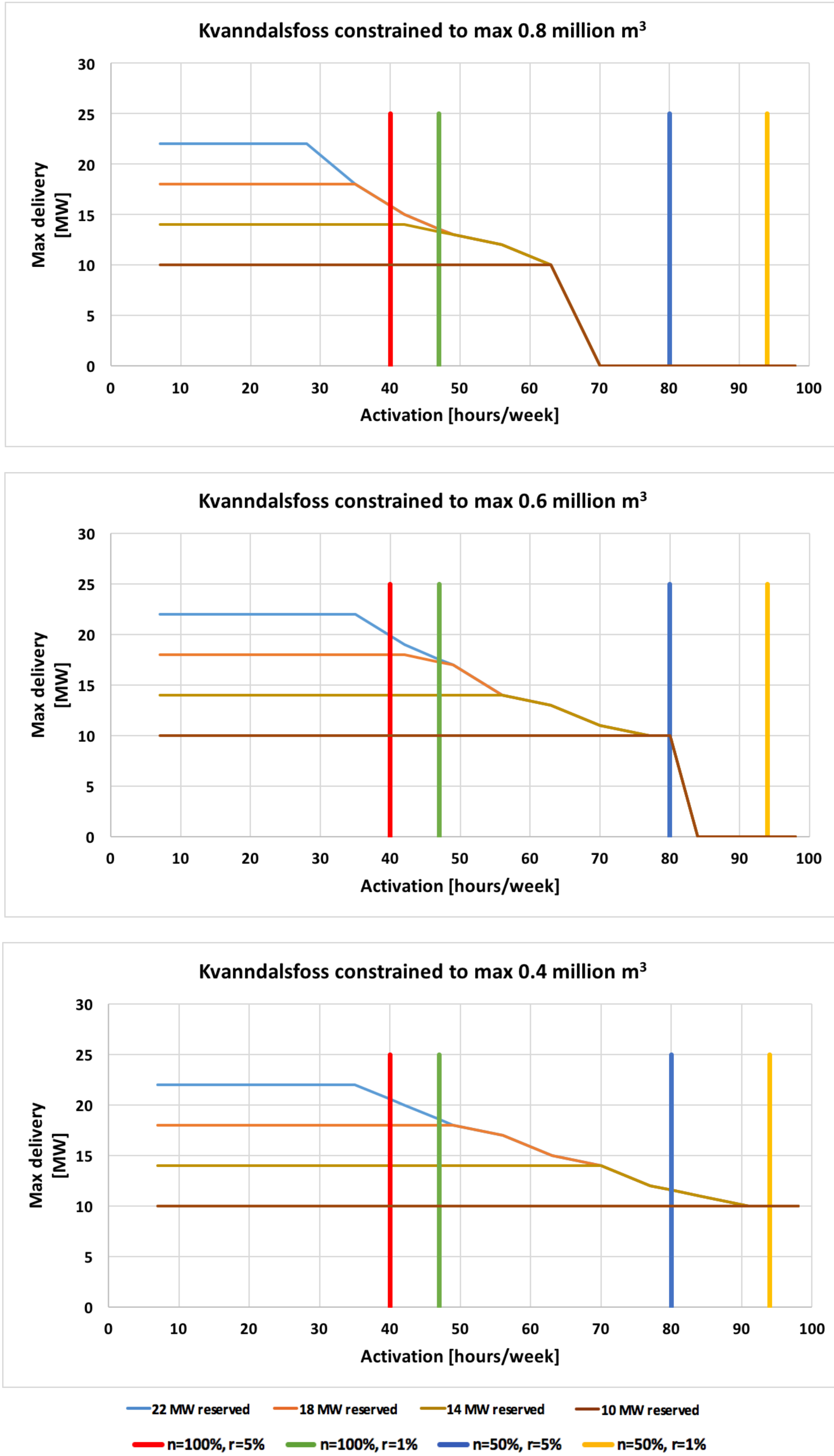

Figure 4.6: Delivered reserves from Kvanndal

The costs of delivering reserves at the different risk levels and water availabilities, using a rate of activation of 50%, are given in figure 4.7. As with the other cases, the total opportunity costs are divided by the amount of delivered reserves in order to find the cost per MW, and the costs of delivering reserves follow many of the same patterns as in the other cases. However, when delivering reserves from Kvanndal, the reservoir below the plant is partly emptied in order to deliver more reserves. Consequently, the total opportunity costs are increasing as less water is stored in the reservoir. Hence, it is not profitable to constrain the water level more than necessary for delivering a certain amount of reserves. Although, more reserves can be delivered as less water is stored in Kvanndalsfoss.

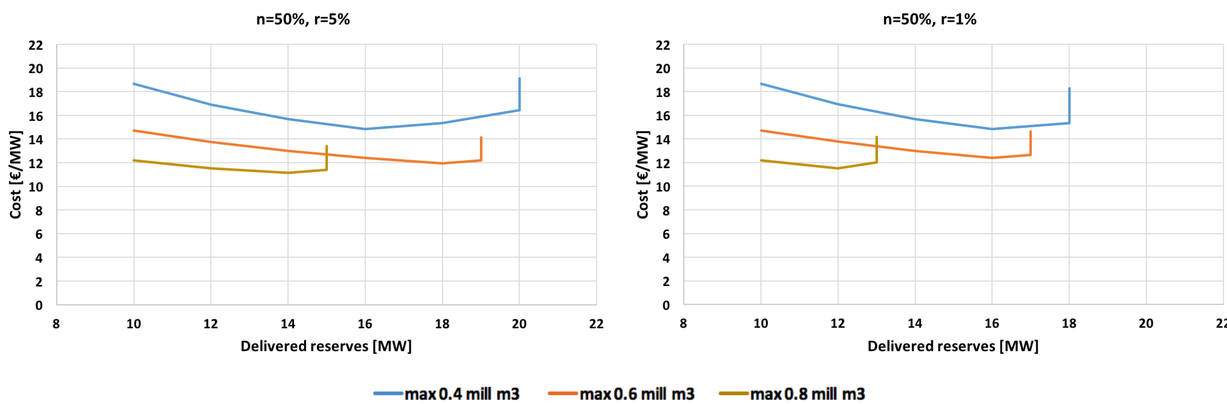

Figure 4.7: Costs of delivering reserves from Kvanndal

As seen from the results, the amplitude of the costs per MW of delivering reserves is much higher at Kvanndal than in the other cases. One of the reasons is because Kvanndal is feeding Suldal 2 with water, and a restriction at Kvanndal also limits the production at Suldal 2 significantly. Additionally, storing water at Kvanndalsfoss is very valuable. As the head at Suldal 2 is about twice of the head at Kvanndal, one cubic meter of water in Kvanndalsfoss can generate about twice as much energy as one cubic meter of water at Sandvatn. As the production at Kvanndal is restricted in order to keep the reservoir level low at Kvanndalsfoss, the water consumption is also reduced. Hence, the inflow to Suldal 2 is reduced by the same amount. This lowers the production from Suldal 2 about twice as much as from Kvanndal. Additionally, the maximum plant discharge at Suldal 2 is twice the maximum plant discharge at Kvanndal. Because the water level in Kvanndalsfoss is constrained, only a smaller share of the the water from Kvanndal can be stored in the reservoir. As the inflow to Kvanndalsfoss is in fact the plant outlet from Kvanndal, only a fraction of the generation capacity at Suldal 2 can be used most of the time. This happens since Suldal 2 is dependent on water in the reservoir, in addition to the inflow, to produce at the plant's maximum generation capacity. However, when the reservoir level is constrained, the reservoir can not store much of the inflow from Kvanndal. Hence, the reservoir is emptied quickly during maximum production at Suldal 2. When the reservoir is empty, the plant can only produce the inflow which is at most half of the inflow needed for producing at maximum capacity. Additionally, the production at Kvanndal is constrained, lowering the inflow, and hence the production at Suldal even more. Because of this cascade effect, the total opportunity costs of restricting the reservoir volume at Kvanndalsfoss get very high. As the reservoir level has to be low in order to deliver reserves from Kvanndal without spilling water, the costs of delivering reserves become high.

Delivering reserves from both stations

Based on the costs of delivering reserves from the two stations separately, it is clear that the total opportunity costs are much larger when the reserves are delivered from Kvanndal than Suldal 2. When the capacity is reserved from both stations, and the distribution is based on minimizing the total costs, more capacity is reserved from Suldal 2 as long as these reserves are cheaper. Additionally, Suldal 2 has a larger generation capacity than Kvanndal, and a larger share of the capacity can therefore be reserved from Suldal 2. Therefore, more water is used for activation at Suldal 2 than at Kvanndal, resulting in a chance of water unavailability in Kvanndalsfoss as the extra water used at Suldal 2 may empty the reservoir. Therefore, different amounts of water have been withheld in Kvanndalsfoss from the production plan, in order to be able to deliver more reserves without emptying the reservoir when both plants deliver reserves. Since water has to be withheld in the same way as when the reserves are delivered from Suldal 2 only, the analysis has been carried out withholding the same amounts of water. Hence, the costs of delivering reserves from both plants can easily be compared with the costs of delivering reserves from Suldal 2 only. The results are presented in figure 4.8.

From the results, one can see that a significant amount of the reserved capacity can be delivered when the rate of activation is 50%. If the rate of activation is 100%, only about half of the reserved capacity can be activated. Additionally, a much larger amount of reserves can be delivered from the hydro system when both plants deliver reserves compared to delivering reserves from Suldal 2 only, when the same volume of water withheld. Furthermore, an increase in the total amount of reserved capacity leads to more water being used at Kvanndal. Hence, more reserves can be delivered when more capacity is reserved.

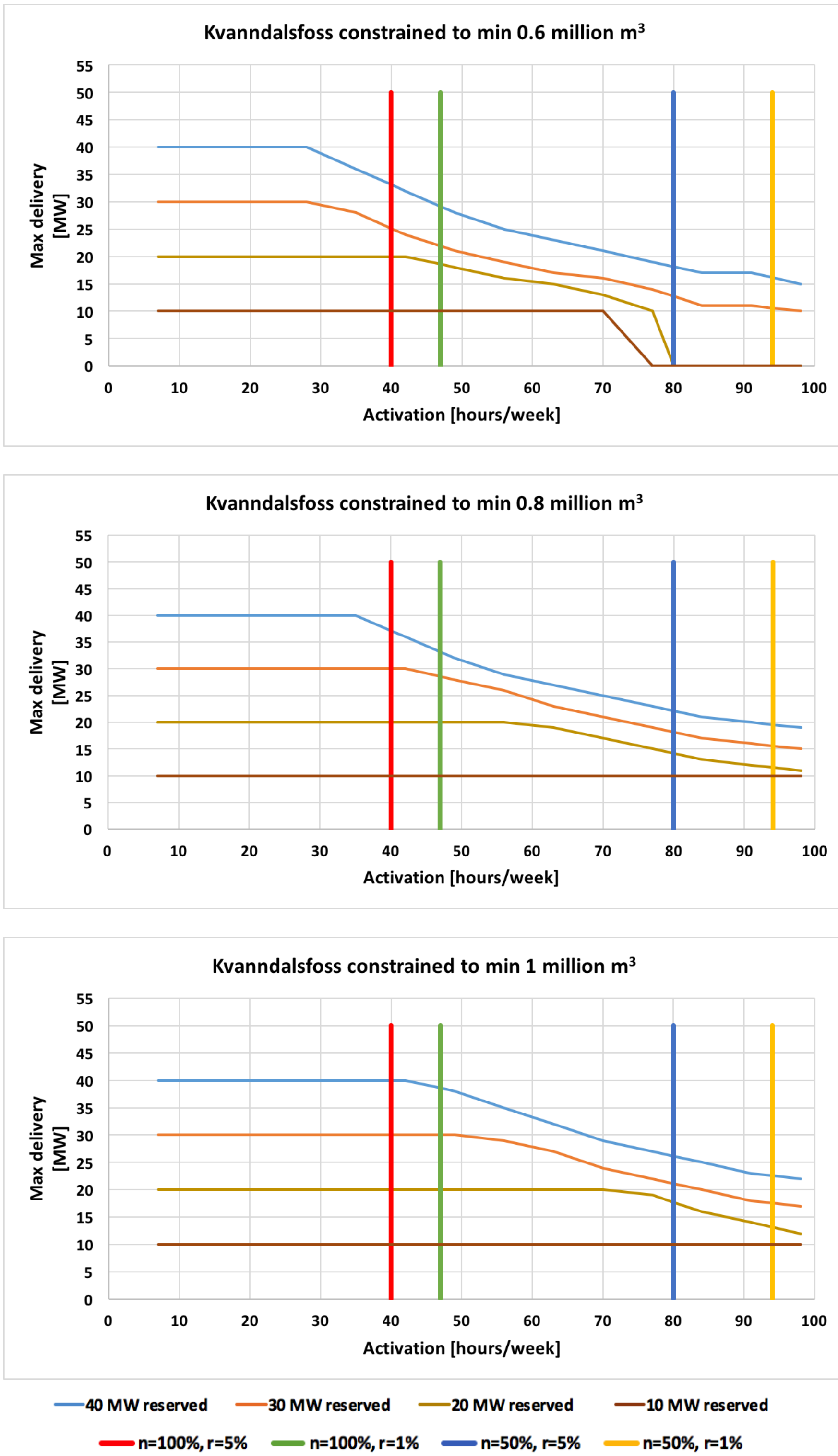

Figure 4.8: Delivered reserves from both plants

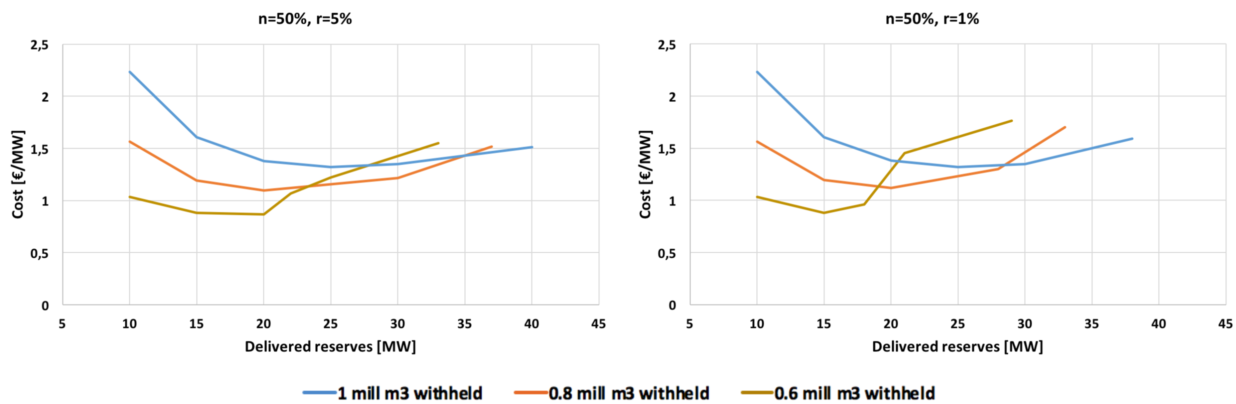

Figure 4.9: Costs of delivering reserves from both stations

The costs of delivering reserves at the different risk levels and restrictions on water consumption, using a rate of activation of 50% are given in figure 4.9. As reserves are delivered at lower costs from Suldal 2 for lower amounts of reserves, the costs per MW of delivering smaller volumes of reserves from both plants are very similar to the costs of delivering reserves from Suldal 2 only. However, the marginal cost of delivering reserves increases as more capacity is reserved. Therefore, all of the reserves are delivered from Suldal 2 up to the point where the marginal costs of delivering reserves from Suldal 2 and Kvanndal are equal. After this point, a further increase in reserved capacity is distributed over both plants, so that the marginal costs stay equal. Hence, all of the reserves are delivered from Suldal 2 about to the volume corresponding to the maximum amount of delivered reserves from Suldal 2 only. At this point, capacity is reserved from Kvanndal also. Hence, the costs per MW start to increase, as no more reserves can be delivered from Suldal 2 at low costs.

When all the water at Kvanndalsfoss is used for activation at Suldal 2, only additional capacity reserved from Kvanndal contributes to more reserves being delivered, as water unavailability is not a problem in Sandvatn. However, when more capacity is reserved in total, some of this capacity is distributed to Suldal 2 also. Hence, the rate between the increase in delivered reserves and the reserved capacity gets low when Kvanndalsfoss is nearly empty. This is resulting in a higher cost of delivering more reserves. Additionally, the maximum amount of reserves which can be delivered will not be reached due to water unavailability, but when the maximum amount of reserved capacity from the generator at Kvanndal is reached. This is because more reserves can be delivered from Kvanndal as long as more capacity is reserved.

As stated earlier, the costs per MW of delivering reserves from both stations follow the same pattern as the costs of delivering reserves from Suldal 2 for low amounts of reserves. However, when Kvanndal is also contributing with reserves, the costs per MW do not nearly reach the same magnitude as when the reserves are delivered from Kvanndal only. This is because the reservoir level in Kvanndalsfoss has to be kept low when the reserves are delivered from Kvanndal only, which has a very high cost. This is not necessary when delivering reserves from both plants, as the extra water used at Kvanndal does not accumulate at Kvanndalsfoss, but is used by Suldal 2. It is therefore possible to deliver much more reserves, to a low cost per MW when the reserves are delivered from both stations.

Additionally, the extra water used to activate the reserves at Kvanndal is provided at Suldal 2. Hence, more reserves can also be delivered from Suldal 2 when more capacity is reserved from Kvanndal. This is illustrated in figure 4.10, where a total of both 20 and 40 MW have been reserved from the hydro system when 0.6 million m^3 of water is held off, and the capacity is distributed at the lowest total costs. As more than 20 MW is available from Suldal 2 at low costs, only spare capacity is reserved from Kvanndal when the total amount of reserved capacity is 20 MW. If all the capacity is needed for activation, the water in the reservoir holds for about 50 hours with activation in the given week before the reservoir is empty. However, when 40 MW is reserved in total, Kvanndal also contributes with reserved capacity. Hence, the reservoir is not nearly emptied when 20 MW is activated for 50 hours. This is because more water is routed from Sandvatn to Kvanndalsfoss when Kvanndal is also activated.

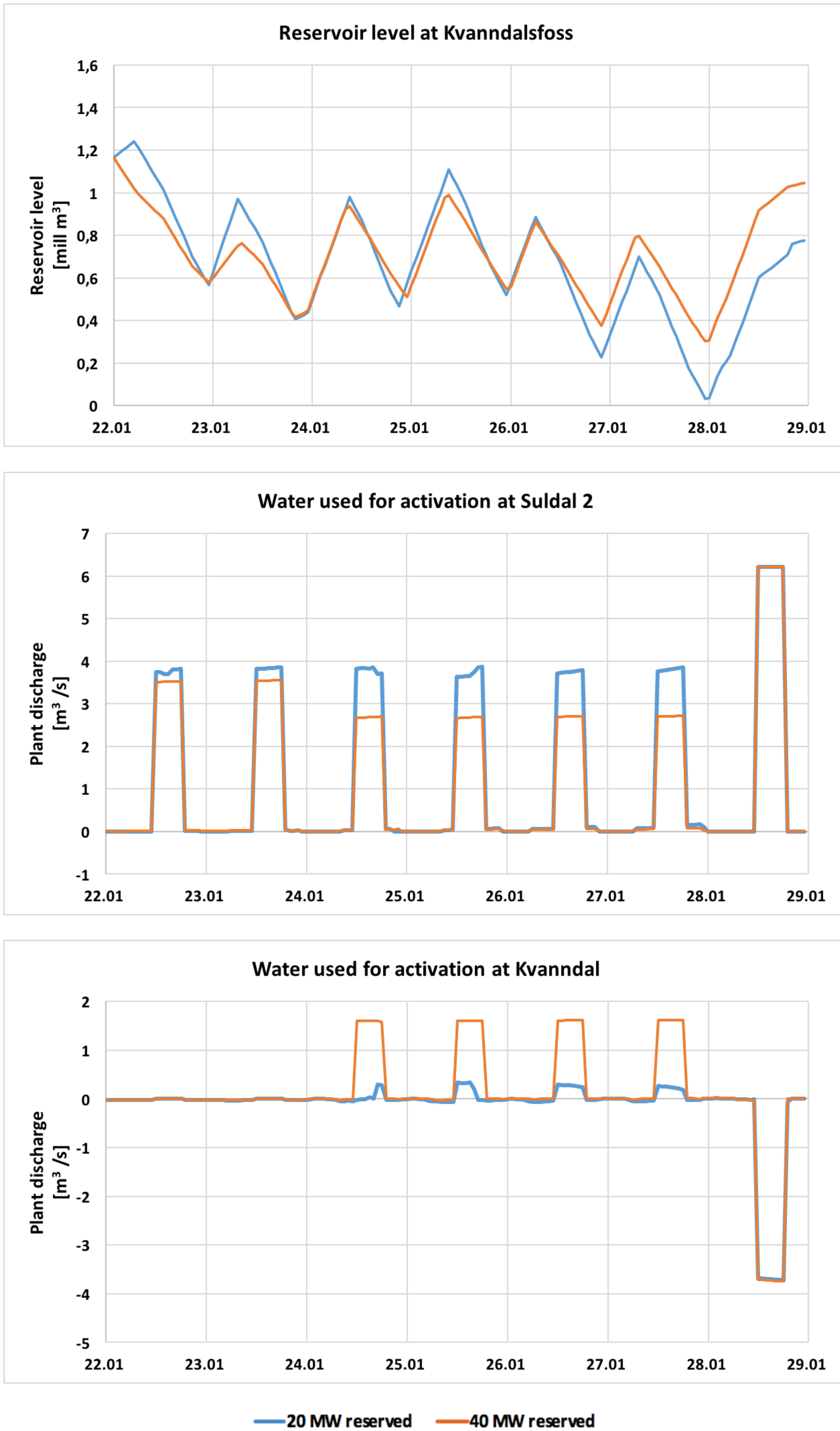

Figure 4.10: Activating reserves with different amounts of capacity withheld

Investigating different strategies for distributing reserved capacity

As concluded, higher amounts of reserved capacity from Kvanndal make it possible to deliver more reserves from both plants for a higher number of hours. In order to deliver a higher share of the reserved capacity, or to reduce the risk of water unavailability, the distribution of capacity can therefore be carried out using a rate between the share of the total capacity which is reserved from the two plants, ignoring the total opportunity costs. In doing so, capacity is available at Kvanndal even when smaller amounts of total capacity are reserved. In order to evaluate this strategy, the analysis has been carried out reserving 75% of the total capacity from Suldal 2, and 25% of the total capacity form Kvanndal. Additionally, the total amounts of reserved capacity have been set to 20 MW and 40 MW, and 0.6 million m^3 of water is withheld at Kvanndalsfoss. Next, the amounts of reserves which can be delivered using this strategy are compared with the amounts of reserves which can be delivered when the reserves are distributed based on the lowest total costs. The results are presented in figure 4.11.

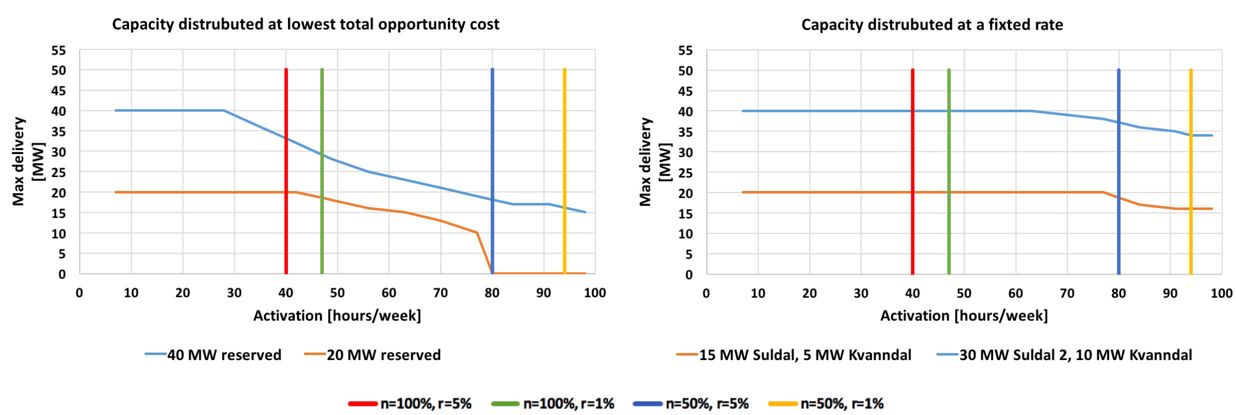

Figure 4.11: Delivering reserves using the two different strategies

As expected, the amounts of reserves which can be delivered decrease less rapidly with an increased amount of hours with regulation when a higher share of the total capacity is reserved from Kvanndal. If the rate of activation is 100%, no reserves can be delivered if 20 MW is distributed at the lowest total opportunity costs for both risk levels. If 40 MW is reserved, about half of the reserved capacity can be delivered before the reservoir is empty. However, if the reserves are distributed using a fixed rate, almost all of the capacity can be delivered, both if the total amount of reserved capacity is 20 MW or 40 MW. Hence, the risk of running out of water is greatly reduced when the reserves are distributed at a fixed rate.

Additionally, the costs per MW of delivering reserves when a total amount of 40 MW is reserved with the different strategies are analysed. These results are given in figure 4.12.

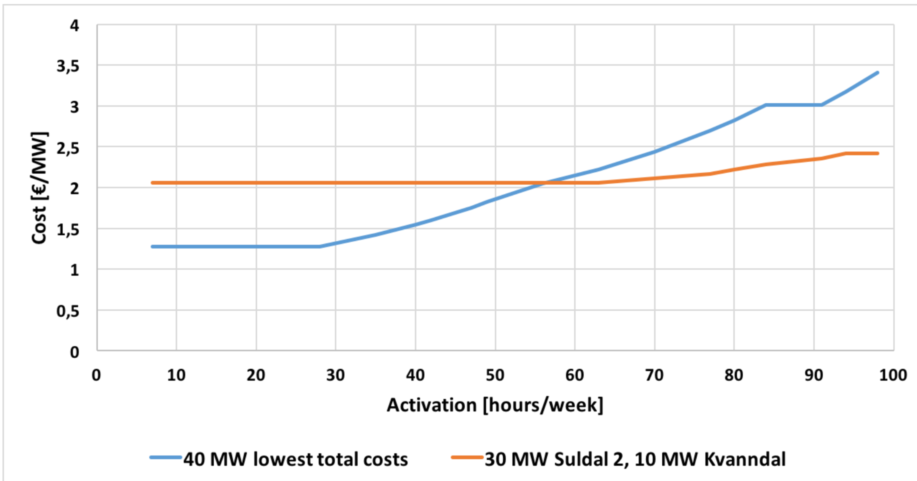

Figure 4.12: Costs of delivering reserves with the different strategies

When the reserves are distributed at a fixed rate, the total opportunity costs are of course higher than if the reserves are distributed at the lowest total opportunity costs. As all of the 40 MW can be delivered in both cases when activation is needed less frequently, the total opportunity costs are divided by the same amount of reserves when finding the costs per MW. However, less reserves can be delivered if activation is needed more often when the distribution is done at the lowest total costs. Although the total opportunity costs are higher when the reserves are distributed using a fixed rate, the amount of capacity which can be delivered is not significantly decreased when activation is needed more frequently. Hence, the cost per MW increases when the reserves are distributed at the lowest total costs, but stays more or less unchanged in the case when the reserves are distributed at a fixted rate. Therefore, if the number of hours with activation gets high, the cost per MW is lower when the reserves are distributed using a fixed rate. Hence, it may be profitable to distribute the reserves using a fixed rate if the capacity is often activated, even though the reserves are distributed at higher opportunity costs. Additionally, the risk of running out of water is reduced when the capacity is distributed at a fixed rate. Hence, in some cases power producers may want to pay these extra costs in order to reduce the risk of water unavailability.

4.4 Limitations of Assumptions

There are several limitations in this work which have to be addressed. First of all, when finding the maximum number of hours with activation based on a given risk level r, historical data of the Nordic power system is used in order to obtain the assumed normal distribution of the number of hours with activation within a week. However, as more of the produced power in the power system is expected to come from intermittent renewable energy such as wind and solar power, more reserves are needed. Hence, using the mean of the last years' data of the power system may not give a correct indicator of how much reserves that are needed from hydro power in the future, as both the total amount of reserves and the share of reserves from hydro power is expected to increase.

Next, in this work, only one combination of hours with activation within the week is analysed. Hence, the amount of reserves which can be delivered is verified for the exact same pattern of hours where the power system is in unbalance. However, there are a very high number of possible combinations of when the reserves are needed for activation. For each combination, the amount of reserves which can be delivered may be different, as activation in one hour may empty the reservoir, while activation in another hour may not empty the reservoir. In order to solve this, an algorithm for picking the worst possible combination which verifies the solution for all other combination would have to be found.

Additionally, using a constant value on the rate of activation is not representing the reality properly. If the share of the total activation were to be determined by a rate, this rate should be both variable and very dynamic. This is because the cost of activating reserves is very state dependent, and is determined by factors as plant production, reservoir levels and inflow, among others. Additionally, the need of reserves in different areas may vary within the year, as for instance harsher weather conditions during the winter or more lightning activity during the summer increases the frequency of transmission outages. Since the regulation of the power system is distributed over all of the participants in the reserve energy market, some sort of technique is needed in order to find each participants' share of activation.

Finally, even though the hours with activation is picked randomly, the hours with activation is known in advance. If capacity is delivered from several units, the model is thereby able to optimize the distribution of activation in one hour in order to avoid water unavailability in the next. In reality, the power producer may know the expected amount of hours she has to activate the reserved capacity for, but she does not know when the reserves are needed. Hence, the distribution of activated reserved can not be decided based on known future activations, which it is in the analysis. Although, if a reservoir is running low, the power producer can still distribute the activation in a way that routes more water from a reservoir with more water to a reservoir with less water.

Chapter 5

Conclusions

From the results in this analysis, several conclusions can be drawn. Most importantly, it is clear that the methodology developed in this work successfully assesses the amounts of reserves which can be delivered, and produces realistic results with the assumptions made. Hence, the results are verifying that the developed methodology, which uses SHOP in innovative ways, is adequate for production scheduling in several markets. Additionally, the results also illustrate concepts which are very valuable for market participants who deliver ancillary services.

The first concept which the results illustrate is that the amounts of reserves which can be delivered are limited by the water availability and flexibility of the hydro system. Hence, the water behind capacity can not be ignored when delivering reserves, and the hydrological constraints must be considered when planning in several markets. Next, the results show that the delivered volumes and costs in the regulating option power market are to a large extent dependent on the available water in the hydro system. Hence, the water levels in the systems' reservoirs from which the capacity is reserved can be constrained in the production plans in order to be able to deliver more reserves. However, the costs of delivering the reserves are greatly increased when constraining the water levels. Therefore, it is not profitable to constrain these levels more than necessary in order to be able to deliver a given amount of reserves.

Furthermore, in a hydro system which consists of several cascaded hydro power plants, it has been shown that it is beneficial to deliver reserves from the system's plants together, instead of delivering reserves from each plant separately. This is because the extra water which is used for activation at one plant in the hydro system can be used to activate more reserves in another plant in the system. Hence, both the risk of spillage and emptying the reservoirs are reduced, and the water availability is increased. Consequently, more reserves can be delivered at lower costs.

However, when distributing the total amount of reserved capacity over the plants in the hydro system, it is not always beneficial to distribute the reserves at the lowest total costs. Even though the total opportunity costs are higher, distributing the capacity at a fixed rate may result in a better utilization of the water when the reserves are activated, and more reserves can be delivered. Hence, the cost per MW of delivering reserves may be lower even if the distribution is done at higher total costs.

In conclusion, the results in this analysis validates the developed methodology. With a growing demand of ancillary services, the benefits of participating in the balancing markets have a great potential. As the profits generated in these markets are highly dependent on the volumes of reserves which can be delivered, and at which costs, the results in this analysis are of much interest both for power producers and system operators. Additionally, many of the the existing models used in the industry does not take water availability into consideration when planning in the balancing markets. Therefore, these models should be extended with a methodology similar to the one validated in this thesis. If so, power producers would be given better support in deciding the volumes sold in the different markets, which would also be beneficial for the reliability of the power system.

Chapter 6

Recommendations for Further Work

There are several elements in this project which can be extended in further work. First of all, there are a lot of uncertainty related to the input parameters in the analysis. Hence, more precise results may be obtained if the deterministic problem is remodeled to a stochastic problem. For this task, the newly developed model SHARM from SINTEF Energy Research is very suited. In comparison to SHOP, which is a deterministic model and does not include uncertainty, SHARM is based on stochastic optimization which includes uncertainty. Additionally, in both of the hydro systems analysed in this thesis, the planning period is set during the winter season. As there are seasonal variations in both inflow, spot prices and power demand, there are also seasonal variations in the amounts of reserves which can be delivered, and thus the costs of delivering reserves. If data for several weeks during the whole year is used, the seasonal variations in the costs of delivering reserves can be analysed.

Furthermore, the analysis can be carried out for a longer planning period, in order to find the long term reservoir development when reserves are delivered. As the long term strategies in the balancing markets affect both the power producers total revenues and reservoir levels, the water values are also affected when participating in the balancing markets. Thus, the correlation between the water values and the balancing markets is very important for the power producers, and should be further analysed.

Another very interesting path would be to combine the methodology and results from this work with studies such as [13], [14] or [16] where the optimal volumes in the RK market for each hour within a planning period have been found. In doing this, a short term stochastic model could be developed in order to optimize the volume in both the spot market, the RKOM market and the RK market for a given planning period without violating any hydrological constraints, and the risk of water unavailability is considered. In order to obtain a robust model, a more suited methodology for finding the rate of activation would have to be developed, and the solution would have to be verified for the worst possible combination of hours which the reserves can be activated for.

Further work could also involve establishing an optimization model for distributing the activation of the reserves during operation, when capacity is reserved from several units. In doing so, the extra water used for activation could be used more efficiently in other parts of the hydro system, and more reserves could be delivered for a given amount of water. The reserves would then be activated more price efficiently, increasing the income to producers of hydro power while reducing the costs for the system operators.

Finally, when more renewable energy is introduced in the European power system, the hydro power producers' benefits in the balancing markets have a great potential. For the Nordic hydro power producers, this potential is optimally utilized if the Nordic balancing markets are integrated in the European balancing markets, given that there is sufficient transmission capacity between the systems. Consequently, carrying out analysis for the future prices of balancing power in an integrated balancing market is of much interest. Furthermore, the benefits in the balancing markets can be included in the investment analysis of new hydro power projects, to evaluate the value of a higher generation capacity to be utilized in the balancing services. Although hydrological and environmental constraints may be difficult to avoid when planning new hydro power projects, the size of the reservoirs have a great impact on a hydro system's flexibility in the balancing markets. Hence, the value of the added flexibility in the balancing markets should be considered when planning the size of the reservoirs in hydro power projects.

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