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A Method for bidding in sequential Capacity Reserve Markets using mixed-integer programming

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Abstract

System security and power quality is important in today's society and the ability to regulate and balance production and consumption is crucial for any power system. More and more penetration of intermittent production in power systems increases the need for regulation capability and the importance of capacity reserve markets where capacity used for regulation is procured and secured increases too.

Several types of regulation mechanisms are used in a power system, which creates the possibility of several different capacity reserve markets with significant prices. A producer participating in these markets must decide how his limited production capacity should be used taking these markets and other physical power markets into account. A method for finding true costs for capacity reserve supply and for bidding in sequential capacity reserve markets is presented in this report. The method is based on a mixed-integer programming model and work has been done to create and formulate a suitable model. The modeling is implemented with the programming language AMPL and is an optimization model that maximizes total profit on several markets subject to market prices and market obligations for a set of production units. The model is then used to highlight some of the fundamental mechanisms and charactheristics in the markets and to illustrate the bidding method for a price-taking producer in perfect markets.

Price uncertainty in future markets has a large impact on the results from the method and a model version where price uncertainty is included for the spot market is compared to a version where price uncertainty is not included. The reason for this comparison is that hourly spot price forecasts used for short-term production planning in Norway today doesn't consider price uncertainty. The versions are compared for bidding in one capacity reserve market for a number of market clearings where prices for the spot market in the model are taken from real spot price forecasts and real spot price outcomes. It shows that inclusion of price uncertainty gives better bids, but also that adjusting bids to account for price uncertainty can give good results from a model that doesn't explicity include this uncertainty.

The method can in any case calculate valid bids for capacity reserve market solutions that exist today where costs and opportunity costs from all relevant markets can be accounted for. The limitations of the method is mostly connected to what it is possible to describe with mixed-integer programming and the computational efforts and calculation times mixed-integer programming models require.

Preface

This report is the product of the master thesis at the Department of Electrical Engineering, NTNU. It is the last part of a 5-year master of science program at NTNU and marks my graduation from university. My time at university has been filled with great ups and downs and everything inbetween, but it has truly been a fantastic experience and a solid foundation from which new challenges and experiences can be met.

This thesis has been done in cooperation with Statkraft and I would like to thank them for letting me have a desk at their offices where I could work with this thesis and for all the help they have provided. I would also like to thank them for being understanding of my challenges during the work with this thesis and that they have been truly wonderful in every aspect. Finally I would like to thank my supervisor Gerard Doorman for his faith in me and for the help he has provided.

Contents

Chapter 1

Introduction

1.1 Motivation

A deregulated power system usually consists of two types of market mechanisms for operation of the system. A production plan for the next day is established through a day-ahead market. Producers bid in this market and commit to produce their respective accepted volume the next day. To make sure that the system frequency is kept within accepted bands the system is balanced in real-time through different kinds of balancing(regulating) measures. The balancing is done by adjusting production and/or consumption in real time to continuously correct the deviations between these two. These adjustments require compensation and this is facilitated through different kinds of real-time balancing markets or other means. In many cases markets are also put in place to ensure that enough capacity(reserves) are available for the real-time balancing.

Intermittent generation like wind power and solar power are an increasing part of the production mix in many power systems across the world and this type of generation will normally make the challenge of real-time balancing harder. Intermittent generation makes it harder to follow and make good production plans and the demand for balancing increases. The system operator in Norway, Statnett, has experienced that the frequency quality in Norway has gone down the later years[7] and with the anticipation of increasing integration of intermittent generation in the power grid in the future they believe a strengthening of the real-time balancing is needed. They are together with the rest of NORDEL of the opinion that the introduction of automatic secondary reserves, often called load frequency control(LFC), will improve the frequency quality and the system operation[7].

1.2 Problems to be addressed

The introduction of a new market and a new product gives a new opportunity where producers can sell power and possibly return a profit, but a new market also further complicates the producers scheduling problem. A producer's production capacity is limited and the producer must decide how to distribute and schedule this capacity in different markets to maximize his profits. This report will mainly focus on this problem, and a method for bidding will be proposed that hopefully can be useful when dealing with it.

1.3 Progress of this report

This report starts with a short description of different reserve types and a short description of how reserve markets are organized in Norway today. The scheduling or planning problem and the method for bidding is explained further in chapter 3 before a mixed-integer programming model to be used is formulated in chapter 4. Illustration of the model and bidding method with some discussion then follows before benchmarking of bids from two model versions and two additional bid strategies is performed in chapter 8. Some further discussion is included at the end of the report.

Chapter 2

Balancing services

LFC can be classified as a balancing service and is normally referred to as secondary control or secondary reserves. The terminology for balancing services and the manner in which it is organized varies between different countries, and the same can be said of the market solutions, but the principle that balancing services can be divided into three main categories is common. The three categories will in this report be referred to as primary control, secondary control and tertiary control, and table 2.1 summarizes some characteristics of the three control levels.

Table 2.1: Comparison between the three different frequency control levels [8]

<table>
<tr><th></th><th>Primary control</th><th>Secondary control</th><th>Tertiary control</th></tr>
<tr><td>Why is this control used?</td><td>To stabilize the frequency in case of any imbalance.</td><td>To bring back the frequency to the frequency target and to restore the primary control capability.</td><td>To manage eventual congestions, to restore the secondary control capability and to bring the frequency back to target if secondary control reserves is unsufficient.</td></tr>
<tr><td>How is this control acheived?</td><td colspan="2">Automatically</td><td>Manually</td></tr>
<tr><td>Where is this control performed?</td><td>Locally</td><td colspan="2">Centrally</td></tr>
<tr><td>Who sends the control signal to the source of reserve?</td><td>Local sensor</td><td colspan="2">TSO</td></tr>
<tr><td>When is this control activated?</td><td>Immediately</td><td>Depends on the system</td><td>Depends on the system, but slower than secondary control</td></tr>
<tr><td>What sources of reserves can be used?</td><td colspan="3">Depends on the system: partially loaded units, loads, fast-starting units. . .</td></tr>
</table>

Manually activated reserves have in Norway often been called secondary control, but these reserves are actually tertiary control according to the terminology used above. Norway and the NORDEL area, as opposed to e.g continental Europe, have so far not operated with secondary control. The introduction of *LFC* in NORDEL changes this, and Norway and NORDEL will get an automatic secondary frequency response in addition to the automatic frequency response of primary control.

To perform the actual control generating units or consumption units are regulated up or down so that production and consumption matches at all times. For this regulation to take place capacity must be available. For up-regulation generation units must have capacity available that are not in active production so that they are able to increase the production. For down-regulation they must have capacity available that are in active production so that they are able to reduce the production. As seen in table 2.1 the aim of the secondary control is to restore the primary control capability and the aim for tertiary control is to restore the secondary control capability. This means that capacity delivered as reserves for primary control cannot be delivered as reserves for secondary or tertiary control and vice versa.

The primary control is the first and fastest control and is a proportional control where the activation is proportional to the frequency. In Norway all the primary control reserves are supposed to be activated when the frequency reaches 49.9 HZ and 50.1 HZ[1]. In principle the primary control will only stabilize the frequency after a disturbance and not bring the frequency back to 50 HZ. The secondary control is an integral control and has the task of bringing the frequency back to 50 HZ. By doing this it will release the primary control. If the disturbance or imbalance is long-lasting or permanent, due to e.g bad prognosis or loss of a power station, the tertiary control would be activated so that the faster acting controls are able to respond to the continuous stochastic imbalances.

The point here is that *LFC* competes for capacity with all other types of balancing services in addition to spot production, so markets for other control types can't be ignored when discussing markets for *LFC*.

To secure that enough capacity(reserves) are available for the different types of control in real-time, TSOs(transmission system operators) procure reserves ahead of real-time in so called capacity reserve markets. The market solutions used by the TSOs in this respect varies between different TSOs and different countries, but the capacity reserve markets generally clears sequentially, before the spot market and for a given time period that consists of several spot market clearings. The energy reserve markets that remunerates the energy use from activation of reserves are real-time markets that clears *ex-post*, but the organization of these markets and the methods used for remuneration of the energy use differs between different TSOs and countries also here.

2.1 Reserve markets in Norway

Today the TSO in Norway, Statnett, operates capacity reserve markets for primary control and tertiary control. The capacity reserve market for tertiary control has so far only been operated during winter time, when high-load situations are expected in Norway and only for up-regulation reserves. The availability of tertiary control reserves has the rest of the year been deemed sufficient without a capacity payment. The same is the case for down-regulation reserves for the whole year, but this may change in the future. In principle capacity reserve

[1]Norway has actually defined a second type of primary control for when the frequency exceeds this boundary. The control mechanism is the same and generators continue to adjust the power output proportionally to the frequency as long as there is enough capacity

markets exists for all the type of reserves, but a price has so far not always been necessary to fulfill the reserve demand. Secondary control(LFC) has until now not been deemed necessary in the Nordic countries, so the demand for these reserves has always been zero.

The capacity reserve market for primary control is in Norway organized with a weekly and a daily clearing. In the weekly market bids can be delivered for a variety of time blocks in the market period. The time blocks are night(00:00-08:00), day(08:00-20:00) and evenings(20:00-24:00) for weekends(Saturday-Sunday) and night(00:00-08:00), day(08:00-20:00) and evenings(20:00-24:00) for weekdays(Monday-Friday). The daily market clears after the spot market and bids are delivered for each hour the next day. The capacity market for tertiary control is organized as a weekly market with a single product. Statnett also buys some tertiary control capacity at the start of the winter season for the whole season. A capacity reserve market for secondary control that is in the process of being implemented in Norway will probably at least include a weekly market with the same products(time blocks) as for primary control. All markets use marginal pricing where the price is set by the last accepted bid.

Supplying in the capacity reserve markets means that one is obligated to supply for the connected energy reserve markets. The energy reserve markets are the real-time markets where the actual regulation of production is performed. Primary control activation(regulation) is not compensated for in Norway so any costs related to this must be covered through the capacity fee. Tertiary control activation(regulation) are compensated based on bids from suppliers and the price is set by the last activated bid(marginal pricing). Compensation for secondary control activation could be based on bids or e.g. a fixed price coupled to the spot price, but it will certainly be compensated.

Chapter 3

Planning problem

Part of the planning problem for Statkraft and other power producers is how to best schedule the production capacity of their generation units to fulfill their market obligations from physical power markets. This is a quite natural optimization problem. The producers' physical power market obligations comes from accepted bids on the different markets, so another part of the planning problem is how and what to bid on the different markets.

All physical power markets in Norway use marginal pricing, and if market power for certain producers exists it is not allowed to use it. So the bidding problem for producers in Norway basically reduces to finding and bidding the marginal costs in each market. Statkraft is among other things owner and operator of hydro-power in Norway. Hydro-power uses water as the resource for power production and the marginal production costs for hydro-power is based on the so called *water value*. Exactly what the *water value* is and methods to calculate it will not be discussed here, but it is basically the resource cost for hydro-power plants similar to what the gas price would be for gas-power plants that uses gas as the resource.

Statkraft uses these *water values* together with the available production capacity as the basis for bids in the spot market. The spot market is a day-ahead energy market that matches bids from the supply side(producers) with bids from the demand side(consumers) for each hour the next day. Based on the obligations from the spot market a production plan for the next day can be put together, and Statkraft uses a mixed integer optimization program(MIP) called SHOP as decision support for finding their optimal production plan. SHOP is a short term hydro power optimization program with a typical planning horizon of one week. Statkraft runs SHOP each day after the spot market clears and uses the known spot obligations for the next day with a deterministic price prognosis for the rest of the week to optimize their unit commitments. This way a good production plan for the next day can be found. SHOP has so far only optimized against spot obligations, but functionality are now being developed to also optimize against primary control reserve obligations[2]. The fulfillment of reserve obligations has so far been taken care of manually by operators in the daily production planning.

Capacity reserves compete with or directly affects available capacity and production in the spot market. This goes both ways with spot production also directly affecting available capacity for reserves. For bidding in the weekly primary control capacity reserve market Statkraft runs SHOP against a deterministic spot price prognosis for the relevant period. Likely available reserve capacity for the different products is then found and operators set the price and volumes of the bids based mostly on experience.

With this method the potential profit to be made in the reserve capacity markets are not really taken into account and the bids for primary control capacity reserves are mostly made up of capacity that doesn't have opportunity costs related to the spot market. The spot supply will just be based on the marginal production costs and will be very little affected by supply of capacity reserves. In Norway the availability of capacity for the different types of reserves has been quite good giving low prices and low income in absolute terms compared to the spot market. So the focus on optimal bids in cases with significant prices in the capacity reserve markets has been quite low. With the introduction of secondary control(LFC) the reserve markets may play a more important role, and with expected tighter integration and exchange of reserves with countries that has larger and more active reserve markets the potential for profit in these markets may be hard to ignore.

We will try to take a look at how and if a method with a MIP-model similar to SHOP that uses branch and bound can be used as decision support for bidding for a producer that wants to optimize his unit commitment subject to all possible physical power markets.

3.1 Bidding procedure

The producer wants to maximize his total profit. He has limited production capacity, but has the freedom to choose in which markets he wants to sell this capacity. With the three different control types presented in chapter 2 there may exist a number of possible products and markets where this capacity can be sold. These markets include the spot market which is an energy market and capacity and energy markets for the different control types, both for up- and down-regulation. In addition to this several markets for the same product may exist as exemplified by the week-ahead and day-ahead markets for primary control capacity reserves in Norway. The capacity use in the possible markets is linked to each other in different ways. The same capacity can e.g. not be sold in both the week-ahead and the day-ahead market for primary control capacity reserves. All the reserve markets exclude each other in that the same capacity can only be sold in one of them. Up-regulation reserves exclude spot supply and vice versa, while down-regulation reserves forces spot supply. Spinning requirements for primary and secondary control means that a generating unit must have active production(spinning) and this will in addition force at least the unit's minimum production for up-regulation reserves and above the minimum production for down-regulation reserves[1].

The optimization problem for a producer in markets with perfect competition[2] then consist of maximizing the profit from supply on the different markets subject to the market prices, the costs of supply and the constraints on capacity use. A MIP-model with branch and bound would give the optimal unit commitments and dispatches in this case, assuming that the market prices are known or the uncertainty of the market prices are perfectly accounted for.

When bidding for a market with marginal pricing a producer should in theory deliver bids for his whole supply capacity based on the marginal costs of supply. This marginal cost of supply in one market would depend on the prices and the potential for profits in other linked markets through so called opportunity costs. A MIP-model will as mentioned find the optimal unit commitment and dispatch on all markets and this can be used to deliver bids where all opportunity costs are included in addition to the direct costs of supply.

The general method for using a MIP model as decision support for bids would then be to choose a price level for the market in question and run the model against price forecasts or

[1] The unit must have at least the minimum production to not shut down so spinning down-regulation reserves must be supplied from active production above the minimum production level.

[2] Meaning that he is a pure price taker on all markets

obligations[3] in all other possible markets. The model would allocate a certain capacity volume to the market in question and this would be the volume where the total profit is maximized for the given prices. By running the model multiple times for different price levels the result would be price and volume pairs for the market in question that could be used for bidding.

As an example consider just the spot market and the evening-product(20:00-24:00) for weekdays in the weekly capacity market for primary control reserves(PRIM) in Norway. The market for PRIM clears before any of the relevant hours clear in the spot market. A price is chosen for the PRIM market and the profit maximizing MIP-model is run against a price forecast for the relevant hours in the spot market. Doing this for several chosen prices in the PRIM market gives price-volume pairs used for bidding.

The difficulty is that the prices of the spot market in the example would be uncertain like all prices of future markets would be, so the effect of all uncertainties must be perfectly accounted for the bids to be optimal.

A good presentation for this problem of self-commitment in energy and reserve markets for producers under uncertain market prices can be found in [4], where the problem is investigated using a backward dynamic programming method.

[3] The market obligations would be known for markets that has already cleared

Chapter 4

Model formulation

The best way to account for uncertainty in a MIP-model would probably be with a stochastic MIP-model. A stochastic SHOP is desirable from Statkraft's point of view and would probably give better support for production planning than today's deterministic SHOP. However, a satisfactory stochastic MIP-model used for hydro optimization is still far away, and including all reserve markets in addition to the spot market makes it even harder. The need for method to bid in capacity reserve markets is here now, so we will focus on the possibilities of today's short-term hydro-optimization models to serve as decision support for bidding.

We will start by creating a MIP-model that includes the spot market and capacity markets for reserves, but that neglects the real-time energy reserve markets. As per today these markets are not specifically considered in Statkraft's bids for the spot market or the capacity reserve markets, but we will discuss the impact of these markets further later in the report. We will, since the focus is on the markets, simplify the modeling of hydro reservoirs and units a great deal compared to the modeling in SHOP, but both SHOP and the model in this report are based on the same mixed integer programming principles. Including all the capacity reserve markets in SHOP and the obligations from these markets in a similar way to what will be done here should not be a problem as shown by the inclusion of primary capacity reserves in [2].

For this model we assume a planning period, e.g a day or a week, where all the different capacity reserve markets has the same resolution with the resolution being the whole planning period. This means that the price is given per MW for the whole planning period and the supplied capacity must be available at all times in this period. The spot market has an hourly resolution and a price for each hour. A separate capacity market for all the control types and regulating directions are modeled and separate markets for the two types of primary control in Norway(*FNR* and *FDR*) are also included.

The model consists of a single producer that owns a set of generating units where every unit is able to participate on all the markets.

The model presented here is purely deterministic, but we will later on also use a multi-scenario deterministic model version. Geographical limitations are not considered in this model.

4.1 Nomenclature

Note that all prices are given in EUR/MW. The spot market is originally an energy market with payment per MWh, but with a price and payment for each hour we will use the unit MWh/h instead. Parameters start with capital letters, while variables starts with small letters. Names and subscripts *fnr*, *fdr*, *lfc* and *rk* relates the parameters or variables to the different capacity reserve markets. These are the norwegian shorthand names for the markets. *fnr* and *fdr* are the two types of primary control, *lfc* is secondary control while *rk* is tertiary control. *spot* relates to the spot market. Subscripts $+$ and $-$ relates to up- or down-regulation reserves.

Sets:

G	$-$	Set of generating units

Indices:

g	$-$	Generator g in set G of generating units
t	$-$	Time period t, hourly
n	$-$	PQ segment n

Parameters:

T	–	Number of time periods
N_{PQ}	–	Number of PQ segments
$C_{start g}$	–	Start-up costs for generator g (EUR/start
$Y_{max g}$	–	Maximum production capacity for unit g (MW)
$Y_{min g}$	–	Minimum production level for unit g (MW)
$\delta_{max g}$	–	Maximum droop for unit g (%)
$\delta_{min g}$	–	Minimum droop for unit g (%)
$SLP_{g,n}$	–	Slope of PQ segment n for unit g
$PQ_{min g}$	–	Discharge at minimum production level for unit g(MWh/h(?)
$PQ_{const g}$	–	Constant used for PQ curves
$SEG_{g,n}$	–	PQ segment limits for unit g and segment n
Λ_{spot_t}	–	Spot price in period t(EUR/MW)
Λ^+_{fnr}	–	FNR capacity up price for the planning period (EUR/MW)
Λ^-_{fnr}	–	FNR capacity down price for the planning period (EUR/MW)
Λ^+_{fdr}	–	FDR capacity up price for the planning period (EUR/MW)
Λ^-_{fdr}	–	FDR capacity down price for the planning period (EUR/MW)
Λ^+_{lfc}	–	LFC capacity up price for the planning period (EUR/MW)
Λ^-_{lfc}	–	LFC capacity down price for the planning period (EUR/MW)
Λ^+_{rk}	–	RK capacity up price for the planning period (EUR/MW)
Λ^-_{rk}	–	RK capacity down price for the planning period (EUR/MW)
FNR^+_{tot}	–	FNR capacity up obligation for the planning period (EUR/MW)
FNR^-_{tot}	–	FNR capacity down obligation for the planning period (EUR/MW)
FDR^+_{tot}	–	FDR capacity up obligation for the planning period (EUR/MW)
FDR^-_{tot}	–	FDR capacity down obligation for the planning period (EUR/MW)
LFC^+_{tot}	–	LFC capacity up obligation for the planning period (EUR/MW)
LFC^-_{tot}	–	LFC capacity down obligation for the planning period (EUR/MW)
RK^+_{tot}	–	RK capacity up obligation for the planning period (EUR/MW)
RK^-_{tot}	–	RK capacity down obligation for the planning period (EUR/MW)
$C^{\delta}_{max g}$	–	Additional cost per hour for best(lowest) droop setting on unit g (EUR/h)
C^{θ}_{g}	–	Cost per hour proportional to the θ setting on unit g (EUR/h)
VV_g	–	Water value for unit g

Variables:

$y_{g,t}$	–	Total spot production for unit g in time period t(MW)
$ys_{g,t,n}$	–	Production from segment n for unit g in time period t(MW)
$q_{g,t}$	–	Discharge for unit g in time period t(MWh/h)
$fnr^+_{g,t}$	–	FNR up capacity supply from unit g in time period t (MW)
$fnr^-_{g,t}$	–	FNR down capacity supply from unit g in time period t (MW)
fnr^+_{tot}	–	FNR up capacity supply for the total planning period (MW)
fnr^-_{tot}	–	FNR down capacity supply for the total planning period (MW)
$fdr^+_{g,t}$	–	FDR up capacity supply from unit g in time period t (MW)
$fdr^-_{g,t}$	–	FDR down capacity supply from unit g in time period t (MW)
fdr^+_{tot}	–	FDR up capacity supply for the total planning period (MW)
fdr^-_{tot}	–	FDR down capacity supply for the total planning period (MW)
$lfc^+_{g,t}$	–	LFC up capacity supply from unit g in time period t (MW)
$lfc^-_{g,t}$	–	LFC down capacity supply from unit g in time period t (MW)
lfc^+_{tot}	–	LFC up capacity supply for the total planning period (MW)
lfc^-_{tot}	–	LFC down capacity supply for the total planning period (MW)
$rk^+_{g,t}$	–	RK up capacity supply from unit g in time period t (MW)
$rk^-_{g,t}$	–	RK down capacity supply from unit g in time period t (MW)
rk^+_{tot}	–	RK up capacity supply for the total planning period (MW)
rk^-_{tot}	–	RK down capacity supply for the total planning period (MW)
$\delta_{g,t}$	–	Droop setting of unit g in time period t (%)
$\theta_{g,t}$	–	Droop setting replacement variable for linearity, inverse of the droop
$c_{\delta_{g,t}}$	–	Cost for unit g in time period t related to the droop setting (EUR)
$start_{g,t}$	–	Variable that checks if unit g has been started in period t
$u_{g,t}$	–	Binary variable, 1 if unit g is spinning in time period t, 0 if not

All variables are non-negative.

4.1.1 Objective function

$$\begin{aligned} max\text{: } & \Lambda^+_{fnr} \times fnr^+_{tot} + \Lambda^-_{fnr} \times fnr^-_{tot} + \Lambda^+_{fdr} \times fdr^+_{tot} + \Lambda^-_{fdr} \times fdr^-_{tot} \\ & + \Lambda^+_{lfc} \times lfc^+_{tot} + \Lambda^-_{lfc} \times lfc^-_{tot} + \Lambda^+_{rk} \times rk^+_{tot} + \Lambda^-_{rk} \times rk^-_{tot} \\ & + \sum_{g \in G} \sum_{t=1}^{T} \left[\Lambda_{spot_t} \times y_{g,t} - C_{start_g} \times start_{g,t} - VV_g \times q_{g,t} - c_{\delta_{g,t}} \right] \end{aligned} \tag{4.1}$$

The objective of the optimization is to maximize total profit, so we add all income and subtract all costs while maximizing. The income comes from sales on the different markets. The income in the spot market comes from the term $\Lambda_{spot_t} \times y_{g,t}$. This is an hourly income, which is summed over all the generating units and over all the hours(time periods) in the planning period. The income from the capacity reserve markets($\Lambda^{up}_{fnr} \times fnr^+_{tot}$ etc.) is not defined for each unit and neither for each time period. With regard to the time periods, this is because these markets have a resolution equal to the planning period in the model. With regard to the units, this is because we are assuming that it doesn't matter which unit the reserve supply(fnr^{+}_{tot} etc.) is coming from. The supplied quantity of reserves must be available at all times, but a producer with a set of units may choose the units that at any time fulfills this obligation. How this is modeled can be seen in section 4.4.

The costs consists of the water discharge from each unit g in each time period t connected with the relevant water value(VV_g), and the start-up costs of units. In addition to this $c_{\delta_{g,t}}$ is added and represents the cost associated with the droop setting of each unit in each time period. Direct costs for supply of secondary or tertiary capacity reserves are assumed to be negligible.

4.2 Discharge constraints

All the generation units in the model are supposed to be hydro-units, but we are here using a quite simple representation of hydro power stations. We are imagining that each unit is connected to a single reservoir. These reservoirs are 100% flexible and large enough so that the water value will be constant for the whole planning period. No restrictions or couplings concerning water discharge from or between reservoirs are considered and the discharge will only be described by PQ-curves which is the relation between power output and water discharge for generation units. So the reservoirs actually become irrelevant here and a constant water value is defined individually for each unit.

This is a simplification, but with regard to the aims of this model the important thing to describe is the relation between power output and water use. Hydro-units typically have a *best-point* for production at some point below the maximum production level and above the minimum production level. This is where the unit's efficiency is best and where the power output per volume of water discharged is highest and thus where the cost per MW produced is lowest. So the relationship between power output and water discharge is the basis for the marginal production costs of the units and essential in this model. This relationship is not linear, but we will here use an approximation with linear segments.

Figure 4.1 shows an illustration of the PQ-curves in the model. In the figure we use three linear segments. The equations used to describe the PQ relations which are given as constraints to the model are

$$q_{g,t} = PQ_{const_g} \times u_{g,t} + \sum_{n=1}^{N_{PQ}} ys_{g,t,n} \times SLP_{g,n} \qquad \forall\, g \in G, t = 1..T \qquad (4.2)$$

$$y_{g,t} = \sum_{n=1}^{N_{PQ}} ys_{g,t,n} \qquad \forall\, g \in G, t = 1..T \qquad (4.3)$$

$$ys_{g,t,n} \leq SEG_{g,n} \qquad \forall\, g \in G, t = 1..T, n = 1..N_{PQ} \qquad (4.4)$$

The production capacity of each unit is divided into segments($ys_{g,t,n}$) where the limit of each segment is given by $SEG_{g,n}$ as seen in constraint 4.4. Constraint 4.3 gives the total production of the units as the sum of the segments. Constraint 4.2 gives the total discharge for each unit in each hour($q_{g,t}$). Each segment $ys_{g,t,n}$ is defined to start from the end of the segment before(or zero for segment 1) so for the formulation of the model to give meaning each previous production segment must be fully used before any production can be taken from the next segment. This

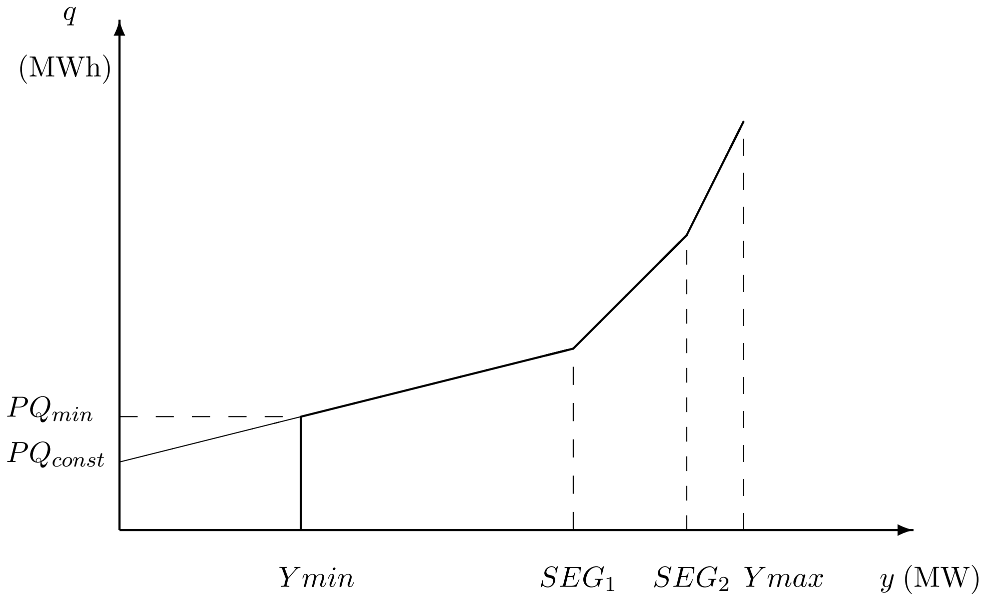

Figure 4.1: PQ-curve

means that the slope of segments $SLP_{g,n}$ must be successively higher. This is also required for the model to be convex.

The slopes of the segments are calculated from corresponding points on the non-linear PQ-curves. With the slopes being successively higher the parameter PQ_{const_g} is added to constraint 4.2 so that the units will have lower efficiency also for production below the *best-point*. This means that the *best-point* of the units in the model always will be at the end of segment 1, and the segments must be scaled accordingly. The slope of the first segment is taken from the discharge at *best-point* and at the minimum production point of the non-linear PQ-curve and the parameter PQ_{const_g} in constraint 4.2 must as seen in figure 4.1 be extrapolated from this. This is done with the function 4.5.

$$PQ_{const_g} = PQ_{min_g} - SLP_{g,1} \times Y_{min_g} \qquad \forall\, g \in G \tag{4.5}$$

So the discharge at minimum production is an input to the model in addition to the effiency(slope) of the different segments. The denomination(unit) for water discharge($q_{g,t}$) is in the model given in MWh/h and is defined with regard to the *best-point* of each unit, so e.g the water discharge for a unit with production of 40 MW at *best-point* would be 40 MWh/h. With the water value(VV_g) given in EUR/MWh, the production costs per MW at *best-point*(end of segment 1) would be equal to the water value. At either side of the *best-point* the discharge per MW increases and the same would be the case for the production costs per MW. The maximum and minimum production levels of the units are taken care of by the constraints 4.20 and 4.21 shown later so it is actually not necessary for the sum of all segments to coincide with the units' maximum production levels as long as it is higher. It is of course convenient if they coincide.

4.3 Primary control and regulation constraints

The ability of a hydro unit to supply primary control reserves depends on the droop setting(δ) of the primary controller. What we will call the *regulating strength*(REG) of a unit can be given by function 4.6[source]. By multiplying the *regulating strength* with the absolute frequency deviation we get the regulated amount from the unit.

$$REG = \frac{2 \times Y_{max}}{\delta} \tag{4.6}$$

Y_{max} is the maximum production capacity of a unit and δ is the droop setting. Defining the regulating strength for each unit g and time period t in the model we get:

$$REG_{g,t} = \frac{2 \times Y_{max g}}{\delta_{g,t}} \qquad \forall\, g \in G, t = 1..T \tag{4.7}$$

A unit's droop setting is normally limited to a certain range. This range is typically from 12% to 2%, but it may vary depending on the desired maximum and minimum droop setting for individual units. This is taken care of by:

$$\delta_{min g} \leq \delta_{g,t} \leq \delta_{max g} \qquad \forall\, g \in G, t = 1..T \tag{4.8}$$

FNR reserves should be fully activated when the frequency reaches 49.9 or 50.1 which gives a band for each regulation direction of 0.1 Hz. *FDR* reserves is defined with a band of 0.4 Hz(49.9-49.5) so the regulation limits for each type can be found with

$$REGFNR_{g,t} = REG_{g,t} \times 0.1 \qquad \forall\, g \in G, t = 1..T \tag{4.9}$$

$$REGFDR_{g,t} = REG_{g,t} \times 0.4 \qquad \forall\, g \in G, t = 1..T \tag{4.10}$$

and quantity constraints for the *fnr* and *fdr* variables given in the model are

$$fnr^{+}_{g,t} \leq REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.11}$$

$$fnr^{-}_{g,t} \leq REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.12}$$

$$fdr^{+}_{g,t} \leq REGFDR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.13}$$

$$fdr^{-}_{g,t} \leq REGFDR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.14}$$

(4.15)

So primary control supply are either constrained by the available capacity of the unit, which can be seen in section 4.4, or by the *regulating strength* of the unit which depends on the droop setting. The problem is that the constraint 4.7 is not linear when the droop setting($\delta_{g,t}$) is a decision variable. This is not possible in a MIP-model. To fix this problem we introduce the new variable ($\theta_{g,t}$) to represent the droop setting and replace equation 4.7 with:

$$REG_{g,t} = 2 \times Y_{max g} \times \theta_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.16}$$

The conversion from $\theta_{g,t}$ to $\delta_{g,t}$ is then done manually outside the model environment with the following relation:

$$\delta_{g,t} = \frac{1}{\theta_{g,t}} \qquad \forall\, g \in G, t = 1..T \tag{4.17}$$

The limits for $\theta_{g,t}$ given in the model and replacing constraint 4.8 becomes:

$$\frac{1}{\delta_{maxg}} \leq \theta_{g,t} \leq \frac{1}{\delta_{ming}} \qquad \forall\, g \in G, t = 1..T \tag{4.18}$$

The modeling of primary control reserves seen here is in line with the modeling suggested by SINTEF for SHOP[2].

Adjusting the droop setting to increase the primary control capability is not cost free. It is assumed that increasing the regulating strength by adjusting the droop setting will decrease the units lifetime. This means that supply of primary control reserves will have a related direct cost. We assume this cost to be linear proportional with θ(constraint 4.19), which in reality means that we assume the cost to be linear proportional with the *regulating strength* of the unit.

$$c_{\delta_{g,t}} = C_g^{\theta} \times \theta_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.19}$$

The ability to supply secondary and tertiary control(*lfc* and *rk*) is not constrained in other ways than the available capacity of the unit shown in the next section, and we assume that direct costs related to supply of these capacity reserves can be neglected.

4.4 Capacity constraints

Capacity is a limited resource and the limitations and relations between capacity use on the different markets will in the mostly used model version of this report be given by the following constraints:

$$fnr^+_{g,t} + fdr^+_{g,t} + lfc^+_{g,t} + y_{g,t} \leq Y_{maxg} \times u_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.20}$$
$$fnr^+_{g,t} + fdr^+_{g,t} + lfc^+_{g,t} + rk^+_{g,t} + y_{g,t} \leq Y_{maxg} \qquad \forall\, g \in G, t = 1..T \tag{4.21}$$
$$y_{g,t} - fnr^-_{g,t} - fdr^-_{g,t} - lfc^-_{g,t} - rk^-_{g,t} \geq Y_{ming} \times u_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.22}$$
$$\tag{4.23}$$

Constraints 4.20 ensures that available capacity for the spot market and the spinning up-regulation capacity markets excludes each other. With the binary variable $u_{g,t}$ representing the spinning state of the unit g the constraint also ensures that the production and supply of spinning reserves is zero if the unit is not spinning or looked at in another way that $u_{g,t}$ must be 1, if unit g has production. Manual up-regulation reserves $rk^+_{g,t}$ may be supplied from stand-by units that starts up, so constraint 4.21 ensures that $rk^+_{g,t}$ can be supplied regardless of the unit state while also taking capacity sold for the other markets into account. Constraint 4.22 ensures that the production must be above Y_{ming} when spinning and that down-regulation capacity reserves can't exceed $(y_{g,t} - Y_{ming})$. This is a simplification since supply of manual down-regulation reserves could exceed this limit by shutting down the unit. However, shutting down the unit would not be an option if the unit is supplying spinning reserves (primary and secondary) at the same time. To model this correctly we introduce a new binary variable:

$z_{g,t}$ – Binary variable, 1 if unit g is supplying spinning reserves in time period t, 0 if not

Constraints that would replace constraint 4.22 would be:

$$
\begin{aligned}
y_{g,t} - fnr^-_{g,t} - fdr^-_{g,t} - lfc^-_{g,t} &\geq Y_{min\,g} \times u_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.24)\\
y_{g,t} - fnr^-_{g,t} - fdr^-_{g,t} - lfc^-_{g,t} - rk^-_{g,t} &\geq Y_{min\,g} \times z_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.25)\\
fnr^+_{g,t} + fdr^+_{g,t} + lfc^+_{g,t} + fnr^-_{g,t} + fdr^-_{g,t} + lfc^-_{g,t} &\leq M \times z_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.26)\\
fnr^+_{g,t} + fdr^+_{g,t} + lfc^+_{g,t} + fnr^-_{g,t} + fdr^-_{g,t} + lfc^-_{g,t} &\geq z_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.27)
\end{aligned}
$$

Constraints 4.26 and 4.27 forces $z_{g,t}$ to one of the states(1 or 0) depending on if spinning reserves are supplied from unit g or not. Constraint 4.24 together with 4.25 ensures that down-regulation reserve can't exceed $(y_{g,t} - Y_{min\,g})$, except for $rk^-_{g,t}$ if the unit are allowed to shut down.

4.4.1 FNR/FDR problem

Another simplification in both of these formulations is the relation between the two types of primary control(*FNR* and *FDR*) in Norway for most hydro-units. The required response time for *FDR* activation is lower than for *FNR*, which beside the frequency band also seperates the products. However, most hydro-units are not able to separate between the products with the control signal being a local signal that is proportional to the frequency. So when *FDR* reserves are activated for frequencies below 49.9 Hz the hydro-units will already have regulated according to the same droop setting for the frequency drop from 50 Hz to 49.9 Hz. This is regardless of if the unit has an obligation to supply reserves for *FNR* or not. Capacity will already have been activated before the first MW of *FDR* reserves are activated. One could say that the supplied amount of FDR reserves would be available in any case, just for a slightly different frequency band(50-49.6 instead of 49.9-49.5), and that this could be acceptable. In that case the modeling so far would be good. The same total amount of primary control capacity that is procured by the system operator would be available at all times, but there would/could be less available capacity of the defined FDR control type. If this is not ok, the additional capacity use related to FDR supply would need to be modeled.

The issue is that the available capacity for the other markets(LFC,RK and spot) should not be affected when there is no obligation for primary control supply regardless of the actual primary control regulation capability(*regulation strength*) of a unit. This is taken care with the constraints 4.11 and 4.12 being inequality constraints. Using binary variables to check if e.g there is an FDR obligation for a unit in a time period and connecting this with the actual FNR regulation according to the droop setting is not possible in this model since the constraints would be non-linear. Both the binary variable and the droop setting are variables. A possibility is to use the characteristics of the variable $\theta_{g,t}$ combined with the associated cost of this variable. Saying that the variable $\theta_{g,t}$ is only constrained downwards by non-negativity and not by a minimum value like in constraint 4.18, we could replace the inequality constraints 4.11 and 4.12 with the equality constraints shown below:

$$
\begin{aligned}
fnr^+_{g,t} &= REGFNR_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.28)\\
fnr^-_{g,t} &= REGFNR_{g,t} \quad \forall\, g \in G, t = 1..T \quad (4.29)
\end{aligned}
$$

In this case the FNR supply would always be in line with the droop setting of the unit, and the use of capacity when supplying FDR would be accurately described using 4.20-4.22 with or without 4.24-4.27. Due to the increasing cost of increasing $\theta_{g,t}$ the primary control capabilities($REGFNR_{g,t}$ and $REGFDR_{g,t}$) would be pushed to zero in the time periods where a unit is not needed for contribution to the primary control supply. So the use of capacity would then also be described accurately for the other reserve products in the relevant constraints. A $\theta_{g,t}$ of zero implies an infinite droop setting $\delta_{g,t}$, so the droop setting would just have to be interpreted as to be the highest setting in the manual conversion in these cases. The slight simplification here is that units may contribute to primary control even for the highest(default) droop settings in the case of free capacity and may supply some primary control capacity free of cost. With this modeling there will be no primary control supply free of cost in the model, but this simplification is not severe in any situations for the purposes of this model, and it will not have any effect at all in capacity constrained time periods.

The problem with the modeling is that the up- and down-regulation FNR supply is not decoupled for individual units. One could think that this was ok with most markets for primary control being symmetric markets. However, even with a symmetric FNR or FDR obligation for a producer the actual supply of up- and down-regulation could come from different units, and the best solution could as an example be to supply up-regulation FNR and/or FDR reserves from a unit at minimum production and down-regulation FNR and/or FDR reserves from a unit at maximum production. This would not be possible with the modeling above since a unit with a regulation capability automatically supplies both types and the capacity use must be accounted for. Splitting the droop setting in two different variables, one for up and one for down, would solve the capacity use problem, but the cost related to the droop setting could then not be described to satisfaction in a linear MIP-model. The effect that the same droop setting is valid for both types and that the cost related to this can be covered by either down- or up-regulation reserve supply, or both, is an important effect and should not be lost. So only one of the equality constraints 4.28 and 4.29 could with this modeling really be an equality constraint and would have to be either

$$fnr^{+}_{g,t} = REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.30}$$

$$fnr^{-}_{g,t} \leq REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.31}$$

or

$$fnr^{+}_{g,t} \leq REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.32}$$

$$fnr^{-}_{g,t} = REGFNR_{g,t} \qquad \forall\, g \in G, t = 1..T \tag{4.33}$$

What type of modeling to use will depend on the market situations and what the goal of the model runs are. E.g. without a price for down-regulation FDR reserves constraints 4.30 and 4.30 would be perfectly acceptable. Without a price for down-regulation manual reserve the simplifications of the version with constraints 4.20-4.22 without 4.24-4.27 will no effect, so it is this version that will be mostly used here.

4.4.2 Actual supply

The supplied capacity in the reserve markets must be available at all times in the planning period, but the producer has the freedom to choose how the supply is distributed among his generation units in each time period. This is modeled with the following constraints:

$$fnr^+_{tot} \leq \sum_{g \in G} fnr^+_{g,t} \qquad \forall\, t = 1..T \tag{4.34}$$

$$fnr^-_{tot} \leq \sum_{g \in G} fnr^-_{g,t} \qquad \forall\, t = 1..T \tag{4.35}$$

$$fdr^+_{tot} \leq \sum_{g \in G} fdr^+_{g,t} \qquad \forall\, t = 1..T \tag{4.36}$$

$$fdr^-_{tot} \leq \sum_{g \in G} fdr^-_{g,t} \qquad \forall\, t = 1..T \tag{4.37}$$

$$lfc^+_{tot} \leq \sum_{g \in G} lfc^+_{g,t} \qquad \forall\, t = 1..T \tag{4.38}$$

$$lfc^-_{tot} \leq \sum_{g \in G} lfc^-_{g,t} \qquad \forall\, t = 1..T \tag{4.39}$$

$$rk^+_{tot} \leq \sum_{g \in G} rk^+_{g,t} \qquad \forall\, t = 1..T \tag{4.40}$$

$$rk^-_{tot} \leq \sum_{g \in G} rk^-_{g,t} \qquad \forall\, t = 1..T \tag{4.41}$$

The hourly supply from each unit g is summed over all the units and the actual supply for the planning period(fnr^+_{tot} etc.) must be equal to or higher than this quantity in every time period of the planning period. This is because the supply in these markets must be available at all times in the planning period.

In addition to these we will implement obligations from the reserve markets by fixing the supply to a minimum value with parameters(FNR^+_{tot} etc.):

$$fnr^+_{tot} \leq FNR^+_{tot} \qquad \forall\, t = 1..T \tag{4.42}$$
$$fnr^-_{tot} \leq FNR^-_{tot} \qquad \forall\, t = 1..T \tag{4.43}$$
$$fdr^+_{tot} \leq FDR^+_{tot} \qquad \forall\, t = 1..T \tag{4.44}$$
$$fdr^-_{tot} \leq FDR^-_{tot} \qquad \forall\, t = 1..T \tag{4.45}$$
$$lfc^+_{tot} \leq LFC^+_{tot} \qquad \forall\, t = 1..T \tag{4.46}$$
$$lfc^-_{tot} \leq LFC^-_{tot} \qquad \forall\, t = 1..T \tag{4.47}$$
$$rk^+_{tot} \leq RK^+_{tot} \qquad \forall\, t = 1..T \tag{4.48}$$
$$rk^-_{tot} \leq RK^-_{tot} \qquad \forall\, t = 1..T \tag{4.49}$$

4.5 Start-up costs

Start-up costs of units is an important factor for the unit commitment problem and is included in the model through the binary variable $u_{g,t}$. We define the variable $start_{g,t}$ to represent if unit g has been started in time period t or not. Constraint 4.50 included in the model fills the variables.

$$start_{g,t} \geq u_{g,t} - u_{g,t-1} \qquad \forall\, g \in G, t = 1..T \tag{4.50}$$

$u_{g,t}$ is 1 if the unit is running and 0 zero if it is not running, so $(u_{g,t} - u_{g,t-1})$, with $u_{g,t}$ representing the unit state of the previous period, becomes 1 if the unit is started, 0 if the unit state doesn't change and - 1 if the unit is stopped. We are only interested in if the unit is started, and with the additional constraint that all variables are non-negative $start_{g,t}$ can be included in the objective function in a way that it will be 1 if unit g is started in period t and zero if not. This happens even though $start_{g,t}$ is a continuous variable.

Chapter 5

Market and product characteristics

We will here try to look at some fundamental mechanisms and characteristics of the markets with some model runs. In [1] a method is shown where prices and volumes for an energy market(spot) and capacity reserve markets for the ancillary(balancing) services of primary, secondary and tertiary control are calcucated simultaneously. In perfect and efficient markets the market prices reflects the marginal cost of supply and/or the marginal benefit of demand, and there will exist a solution or market equilibriums where no market participant can increase their surplus(profit for rational profit-maximizing power producers) by changing any of their market commitments. A method is shown in [1] that finds this solution for a power system with simultaneous market clearings using among other methods lagrangian relaxation. The optimizations in this chapter are actually a variant of this, and especially the first optimization may be looked upon as simultaneous market clearings in each hour.

It is not really valid to interpret the dual values of a MIP-model as prices, since the dual values are given for a given combination of the binary variables, so we will here do an optimization for a set of generating units and look at the resulting volumes to say something about the characteristics of the different reserve markets. To do this we will let the spot demand be represented by spot prices, while the different reserve demands from the set of units are represented by fixed requirements. This could be interpreted as a need for reserves in a specific geographical area where the units are located while the spot price is set by supply and demand in a larger area. By doing a profit maximization we will then get the optimal capacity allocation on the different markets for the set of generating units, which also ideally should be the result for market equilibriums in perfect markets where the reserve markets only consists of these units.

5.1 Model setup

The planning period used here is 5 hours with different spot prices in each hours. Table 5.1 shows the prices for each time period.

The highest and lowest spot price in table 5.1 are based on the real highest and lowest system spot price at Nord Pool in week 45 of 2011. This is not really necessary here since this is just for illustrative purposes, but is done to get realistic magnitude orders. The spot prices has here been put together to be falling for each time period, with the other prices distributed between the two extremes.

The reserve requirements in Norway are very approximately 10% of the total installed production capacity for tertiary control reserves, 1% for FNR reserves and 2% for FDR reserves. We

Table 5.1: Spot prices for basic model test

Time period	Spot price (EUR/MWh)
1	53.86
2	48.26
3	42.66
4	38.82
5	34.99

assume 2% for secondary control. These requirements will be doubled for this optimization and with a total production capacity of about 900 MW in this model setup, the requirements can be seen in table 5.2. The primary control will not be split into FNR and FDR in this optimization, and just the FDR variables will be used.

Table 5.2: Reserve requirements

Reserve type Up-regulation	Demand	Reserve type Down-regulation	Demand
FDR^{+}_{tot}	70	FDR^{-}_{tot}	70
LFC^{+}_{tot}	40	LFC^{-}_{tot}	40
RK^{+}_{tot}	180	RK^{+}_{tot}	180

The generation units used here will be identical except from their marginal production costs, i.e. the water values(VV_g), and the PQ curve is based on one of Statkraft's power stations. The parameters used for the unit description can be seen in table 5.3. No start-up costs are used so that there will be no intertemporal considerations and the cost related to the droop setting is tuned so that the cost per hour is 5 EUR for the maximum *regulation strength*of the units.

Table 5.3: Unit parameters

Unit parameters	Value	Unit parameters	Value
Y_{min} (MW)	13	C^{θ} (EUR)	10
Y_{max} (MW)	89	δ_{max} (%)	12
$Start$ (EUR)	0	δ_{min} (%)	2

The PQ-curve uses 4 segments and is tuned so that the efficiency of the unit for different production levels gives a good approximation of the real PQ curve. Figure 5.1 shows the relative water discharge with respect to the best-point for the PQ-curve used in the model and for the PQ-curve at a given time for the real unit in question.

This optimization will use 10 of these units with the varying water values given in table 5.4

Unit 1($G1$) has the lowest water value, with the water value increasing all the way to unit 10.

Constraints 4.24-4.27 that models the tertiary down-regulation supply accurately are included here.

5.1.1 Results and discussion

The optimization here can be interpreted in two slightly different ways. If we imagine that the set of units represents the whole reserve participating market and the reserve requirements the

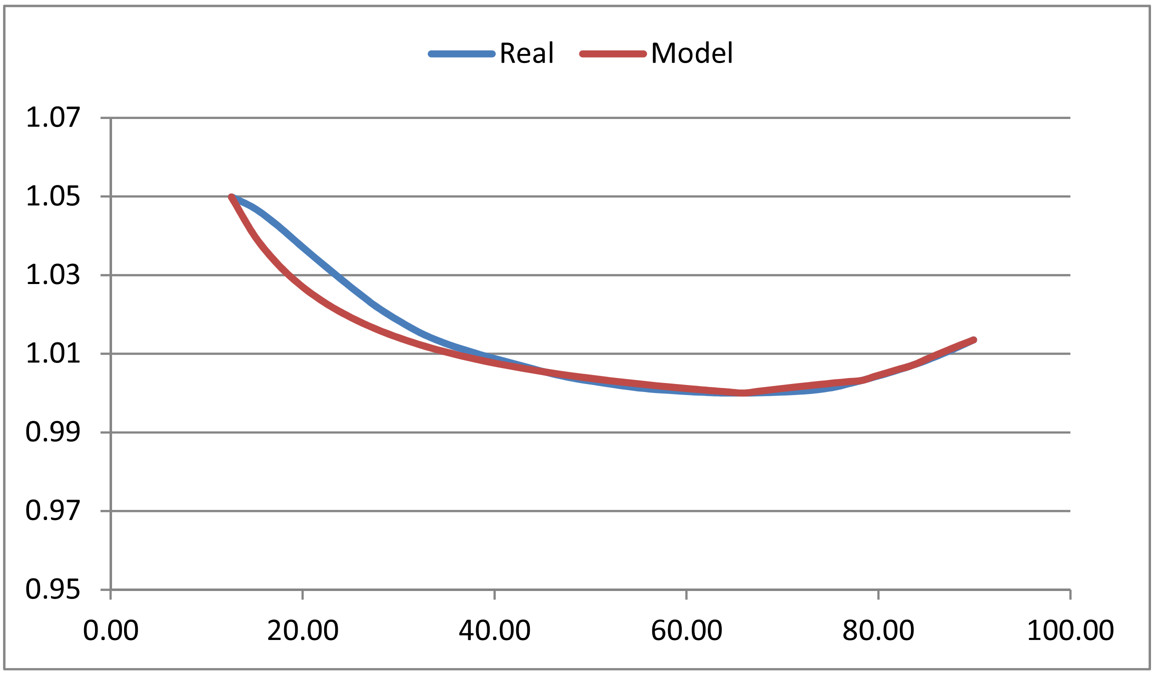

Figure 5.1: Comparison of relative water discharge between the unit in reality and in the model

Table 5.4: Water values

Unit	**VV(EUR/MWh)**	**Unit**	**VV(EUR/MWh)**
G1	34	G6	44
G2	36	G7	46
G3	38	G8	48
G4	40	G9	50
G5	42	G10	52

total market requirements, we get the simultaneous clearing of all markets for each time period. The reserve requirements must be fulfilled in each hour over the whole planning period, but how they are fulfilled are independent from hour to hour and the optimal solution is found in each hour independently. We can also imagine that the set of units represents a single producer that has taken on obligations for the whole planning period from different reserve capacity markets that clears before the first time period and spot market clearing. In this case it is assumed that the producer in each hour can choose how to fulfill his reserve obligations for all the reserve markets and it will be done in the way that his profit his maximized in each hour subject to the spot prices. This is valid for the reserve capacity markets that exists in Norway today(primary and tertiary), since the merit order list for tertiary control activation is updated hourly and the automatic activation of primary control is done locally on each unit. So we will here assume that the same is the case for an automatic secondary control market(LFC).

A very thorough analysis of the exact number values of the results will not be done here, but we will look at the general mechanisms that these results outline. Table 5.5 shows the spot commitment in each hour.

Table 5.5: Spot commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	89	89	89	89	89
G2	89	89	89	89	89
G3	89	89	88	78	78
G4	89	89	78	59	59
G5	87	87	66	13	13
G6	78	78	13	-	-
G7	66	66	-	-	-
G8	13	13	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

We see that even though the spot price in hour 1 is above all the units' production costs some units are not producing at all, and some are producing well below maximum production capacity and even well below *best-point*. The *best-point* is 66 MW for all the units. This is because the reserve requirements for up-regulation must be fulfilled, and this capacity cannot be in active production. In hour 5 we see that even though the spot price is below all the units' production costs(except unit 1) some units are producing so that the reserve requirements for down-regulation can be fulfilled. This commitment is obviously not optimal for the units when considering just the spot market, and opportunity costs would arise when supplying reserves. These costs would be compensated through prices in the reserve markets. The characteristics of the opportunity costs related to the spot market for a unit are a bit different for different types of reserves. This is summarized below for the three types that will have distinct characteristics when considering the spot market.

- Up-regulation manual reserves: For these types of reserves a unit must have capacity available that is not in active production, i.e. spot production. This means that an individual unit's cost of supplying up-regulation manual capacity reserves will always be lower with higher marginal production costs.
- Up-regulation spinning reserves: For these types of reserves a unit must have capacity available that is not in active production, while at the same time producing at least the

minimum production level for the unit. This is because the unit must be spinning. This means that an individual unit's cost of supplying up-regulation spinning capacity reserves will always be lower the closer the marginal production costs are to the spot price.

- Down-regulation reserves: For these types of reserves the reserve capacity consists of active production that may be reduced. This means that an individual unit's cost of supplying down-regulation capacity reserves, manual and spinning, will always be lower with lower marginal production costs.

In this optimization the units are only separated by their water values with everything else being equal. This means that it is this difference that mostly decides the distribution of the units on the different markets. Other differences between units, like maximum and minimum production levels, differences in direct costs for reserve supply and differences in efficiency curves will also affect the optimal distribution of units on the different markets. Even so, there still exist a type of rank between the units on different markets that ensures that market equilibriums and prices in theory can be found where every unit has maximized their profits. Table 5.6 to 5.11 shows the supply of the different reserve types for each unit and hour.

Table 5.6: FDR^{+} commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	-	-	-	-	-
G2	-	-	-	-	-
G3	-	-	1	11	11
G4	-	-	11	30	30
G5	2	2	23	29	29
G6	11	11	36	-	-
G7	23	23	-	-	-
G8	34	34	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

Table 5.7: FDR^{-} commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	6	6	24	-	-
G2	6	6	6	-	-
G3	6	6	6	36	36
G4	6	6	11	34	34
G5	6	6	23	-	-
G6	17	17	-	-	-
G7	23	23	-	-	-
G8	-	-	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

The solution here represents the optimal solution where the demand on all markets in all hours is met with minimum costs. The optimization here may actually be seen as a cost minimization instead of a profit maximization when we interpret the spot prices as a representation for spot

Table 5.8: LFC^+ commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	-	-	-	-	-
G2	-	-	-	-	-
G3	-	-	-	-	-
G4	-	-	-	-	-
G5	-	-	-	40	40
G6	-	-	40	-	-
G7	-	-	-	-	-
G8	40	40	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

Table 5.9: LFC^- commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	40	40	40	-	-
G2	-	-	-	-	-
G3	-	-	-	30	30
G4	-	-	-	10	10
G5	-	-	-	-	-
G6	-	-	-	-	-
G7	-	-	-	-	-
G8	-	-	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

Table 5.10: RK^+ commitment (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	-	-	-	-	-
G2	-	-	-	-	-
G3	-	-	-	-	-
G4	-	-	-	-	-
G5	-	-	-	7	7
G6	-	-	1	89	89
G7	-	-	89	89	89
G8	2	2	89	89	89
G9	89	89	89	89	89
G10	89	89	89	89	89

Table 5.11: RK^- commitment (MW)

Unit	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5
G1	30	30	12	89	89
G2	70	70	70	89	89
G3	70	70	70	2	2
G4	70	70	55	-	-
G5	69	69	30	-	-
G6	48	48	-	-	-
G7	30	30	-	-	-
G8	-	-	-	-	-
G9	-	-	-	-	-
G10	-	-	-	-	-

demand. The only actual(direct) costs in this optimization is the production costs and the costs related to the droop setting of the units. We see from the results how the spot production is maximized for capacity with production costs below the spot price and minimized for units with production costs above the spot price while also fulfilling the reserve demands. In this case the result is that a unit with higher production costs will have equal or lower production compared to units with lower production costs. The impact of the droop setting costs is a bit more interesting. These costs are just related to the droop setting which limits the capability for both up- and down-regulation primary control supplies. This means that a unit that is already supplying a certain amount of up-regulation primary control reserves may also supply the same amount of down-regulation primary control reserves without an increase in the droop-setting costs. So we see in table 5.6 and 5.7 that supply of primary control reserves above the minimum droop setting for up- and down-regulation are mostly put on the same units so that as many units as possible can stay at the minimum droop setting. The minimum droop setting gives here a maximum primary control supply of 6 MW for each unit.

5.1.2 Pricing

The market prices for the different products must as mentioned compensate for the cost of supply. We will take a short look at some of the hours in this respect. In hour 1, we see that the spot price is above all the units' production costs. Enough capacity will, due to the high spot price(demand), be in production so that all down-regulation reserve demand can be met without a capacity price. Up-regulation reserves must be taken from capacity that would otherwise have produced for the spot market, so a capacity price that compensates for this opportunity costs is needed. We see in table 5.8 that it is unit 8 that is fulfilling the up-regulation secondary control (LFC^+) demand. To do this he would require a compensation that at the minimum equaled his profit in the spot market which would be the difference between the spot price and his marginal production cost. If we ignore any impact of the unit efficiency curve this would mean $\Lambda_{spot} - VV_8$ which equals 6 EUR/MW. But it is obvious here that unit 10(and unit 9) would be able to supply LFC^+ for a lower opportunity cost than unit 8. Unit 10 is however supplying RK^+ instead. If unit 10 was to fulfill the LFC^+ demand instead of unit 8, it would then require that unit 8 supplied more RK^+ and the same dilemma would occur since unit 10 obviously could supply this reserve type for a lower cost too. The separating factor between the two types is the spinning requirement. Supply of spinning reserves for the units in question here requires at least the minimum production level($Ymin$). This means that a unit supplying manual reserves(RK^+) can sell the whole unit capacity as reserves, while a unit supplying spinning reserves(LFC^+) can maximum sell the quantity $(Ymax - Ymin)$ as reserves with the rest being sold as spot production. If we assume that unit 8 is the price setting unit for the reserves, it becomes clear that unit 10 is best off supplying exclusively RK^+ capacity with unit 8 supplying the spinning reserves(LFC^+) since unit 10 has a lower profit in the spot market compared to unit 8. Unit 10's required compensation for his RK^+ supply would be above his individual opportunity cost related to the spot market though, since it is now the markets for up-regulation spinning reserves that gives him the highest opportunity costs.

In hour 3 with a medium spot price(demand) there is enough capacity available so that both manual up-regulation reserves(RK^+) and down-regulation reserves can be supplied without opportunity costs. This can be seen by the surplus of capacity for down and up-regulation reserves in tables 5.10 and 5.11. For up-regulation spinning reserves it is not so straight forward. We see in table 5.8 that unit 6 is fulfilling the LFC^+ demand. Unit 6 cannot make a profit in hour 3 with the given spot price, so the production he has in hour 3(the minimum production) gives a negative profit(loss) for unit 6. This production is at least required to supply the spinning up-regulation reserves, so it becomes a cost that must be recovered through compensation for the reserves. This cost is not coupled to the supply of up-regulation spinning reserves since the total cost doesn't change with changing LFC^+ supply. This is different from the supply in hour 1 where the cost was coupled to each MW supplied. So it is actually a fixed cost where the required compensation per MW of LFC^+ supply depends on the volume. Larger supply means lower cost per MW since the cost that must be compensated for is the same regardless. Fixed costs in the normal sense of the word should of course not really be considered when selling this service, but since these costs are only incurred when one chooses to supply LFC^+ they are not really fixed costs. They are coupled to the option of supplying LFC^+ or not, but decoupled to the options of how much to supply.

In hour 5 with a low spot price(demand) there is enough capacity available so that manual up-regulation reserves can be supplied without opportunity costs. For the rest of the reserve types there will be a cost since the required spot production to supply the reserves gives a loss for all the producing units. We see in table 5.8 that unit 5 is fulfilling the LFC^+ demand even though all units below could do this for a lower cost. The mechanisms is the same as in hour 1 and it is the units with the lowest production costs that is supplying the manual down-regulation reserves in this hour with the spinning reserves being pushed to the units with higher production costs. The 'fixed' costs exists also for spinning down-regulation reserves in this case even though the supply for spinning down-regulation reserves is always coupled to spot production for marginal increases in supply. The quantity $Ymin$ cannot be sold as spinning reserves, but must be sold in the spot market so increased supply will help to cover this 'fixed' cost also for spinning down-regulation reserves. This is what separates the manual down-regulation capacity reserves from the spinning down-regulation reserves and equilibrium prices could also here be found such that all units have maximized their profits with the resulting commitments.

This was a quite superficial analysis of the results and the pricing in the markets, but the point is that all the different market prices are correlated with each other and will be a function of supply and demand on all markets. With the demand for reserves being mostly the same at all times in a power system, it is the changing spot demand that will be the driving force behind the prices. The clearest characteristics is that periods with high spot demand will be correlated with high manual up-regulation reserve prices and high spot prices, and periods with low spot demand will be correlated high down-regulation reserve prices and low spot prices. Up-regulation spinning reserves is a bit special in that high up-regulation spinning reserve prices may be correlated with both high and low spot demand periods due to the simultaneous requirement of capacity in and out of production for individual units. Primary control reserves and secondary control reserves has the same capacity characteristics with regard to the other markets, but the limitation on each unit for primary control reserves makes separates them besides just the direct costs for primary control. This makes it possible that it is just not the direct costs that should separate the prices in these two markets. The manual capacity reserves(RK^+ and RK^-) will for all units have equal or lower costs of supply compared to their spinning counterparts, so the prices for these reserves should be equal or lower in perfect markets. The units in a power system that at a given time are competitive for manual up- down-regulation reserves will not change with changing spot demand(prices), while the units competitive for especially up-regulation spinning reserves will change with changing spot demand(prices). Units competitive for down-regulation spinning reserves when a capacity price is needed can change with changing spot demand(prices), but that would be due to differences in maximum and minimum production levels and not because of production costs differences.

The spinning requirement and the minimum production level creates a binary effect for the supply on the different markets, so a marginal analysis of the potential profits in different markets is not really possible and marginal shifts of capacity between different reserves markets is not always possible or desirable for units operating in these markets. This is also what makes a MIP-model suitable to finding optimal unit commitments on the different markets.

5.2 Station specific LFC

The optimization with results in table 5.5-5.11 was for a secondary control market(LFC) where the unit(s) supplying the reserves could change from hour to hour. In a memo on the introduction of LFC markets in Norway[6], Statnett states that the most probable solution at least in the implementation period for *LFC* will be a weekly market with station specific bids. This means that the accepted bids are coupled to specific power stations for the whole bid period. To model this we need to introduce two new variables:

$lfc^+_{ST_g}$	–	LFC up capacity supply from unit g for the total planning period(MW)
$lfc^-_{ST_g}$	–	LFC down capacity supply from unit g for the total planning period(MW)

With this modeling we assume that each unit g in the model is a station of its own. A power station may of course consist of several units, and it is not complicated to model this possibility in a model like this, but we will not do that here.

We replace constraints 4.38 and 4.39 with

$$lfc^+_{ST_g} \leq lfc^+_{g,t} \quad \forall\, g \in G, t = 1..T \tag{5.1}$$

$$lfc^-_{ST_g} \leq lfc^-_{g,t} \quad \forall\, g \in G, t = 1..T \tag{5.2}$$

$$\tag{5.3}$$

and add the following constraints

$$lfc^{+}_{tot} \quad \leq \quad \sum_{g \in G} lfc^{+}_{ST g} \qquad \forall\, t = 1..T \tag{5.4}$$

$$lfc^{+}_{tot} \quad \leq \quad \sum_{g \in G} lfc^{-}_{ST g} \qquad \forall\, t = 1..T \tag{5.5}$$

$$\tag{5.6}$$

This way the supply from an individual unit(station) must be available at that unit in the whole period, and the total supply consists of the sum of supply from individual units(stations).

5.2.1 Results and discussion

Table 5.12 shows the spot commitment from the same optimization as before with the changed market rules.

Table 5.12: Spot commiment with station specific LFC (MW)

Unit	**Hour 1**	**Hour 2**	**Hour 3**	**Hour 4**	**Hour 5**
G1	89	89	89	89	89
G2	89	89	89	89	89
G3	89	89	88	84	84
G4	89	89	78	78	78
G5	87	87	66	13	13
G6	78	78	-	-	-
G7	66	66	-	-	-
G8	13	13	13	13	13
G9	-	-	-	-	-
G10	-	-	-	-	-

We see that the optimal solution has changed quite a bit. The *LFC* demand must now be supplied from the same unit for all hours and we see that unit 8 produces at the minimum level for the low price hours even when units with lower production costs are not producing. It is clear that this gives a higher cost than if the demand was covered with an optimal commitment in each hour as in the previous optimization. This can also be seen by the fact that the objective function value changes from 13 982 to 13 823 for the two optimizations. For a producer supplying these reserves for the whole period it would mean a higher required compensation and for the market as a whole it would mean a higher secondary control capacity price and lower social surplus. One thing to note is that having the market for reserves clear for periods of several spot clearings(hours) instead of in each hour will give lower social surplus[1] by itself when considering that the units of a power system is divided between several independent producers. By taking the extreme of this and saying that each independent producer only has one unit each, we see that the result would be the same as for the rule of unit(station) specific supply.

The reason for all of the above is the mentioned characteristics of up-regulation spinning reserves. The cost of supply for an individual unit will always be lower the closer the marginal production costs are to the spot price. With varying spot prices during the period, it is likely that the demand or obligation optimally should be fulfilled by different units in each hour, which is the case for the optimization seen here. Down-regulation spinning reserves doesn't have the

[1] We are assuming correct prices(bidding) for all alternatives and are not considering factors such as administrative costs etc. for different market solutions here

same characteristic and the capacity price for LFC^{-} wouldn't necessarily increase with varying spot prices and station specific supply. But station specific supply would probably mean that the secondary control energy reserve market is isolated for the capacity that is procured in the capacity market. Activation of down-regulation reserves is best to do at units with high production costs, so this means that the demand also for LFC^{-} probably should be fulfilled by different units in each hour to maximize the social surplus. Energy markets are not included in the model though so station specific LFC^{-} doesn't increase the costs for this optimization.

Another point that can be seen here is the advantage a large producer with many units of varying production costs would have in up-regulation spinning reserve capacity markets where the producers can choose how to fulfill their LFC obligations in each hour over the obligation period. Consider a producer owning and operating the full set of units used in these optimizations against a producer owning only the unit that supplies LFC^{+} capacity for the second optimization(unit *G8*). It becomes clear that the first producer would be able to supply the same amount of LFC^{+} capacity for a lower cost than the second producer. This difference between producers disappears when the supply is unit(station) specific over the obligation period.

The solution used to reduce the effect of these issues in the weekly capacity markets today is to divide the market products for spinning reserves into several specific time periods(see section 2.1). These periods are chosen so that they consist of hours with similar spot demand and thus similar spot prices.

Chapter 6

Bidding

We see that the MIP-model finds the optimal commitment for a producer considering market obligations and/or market prices, so how would the model work when using this for bidding in sequential weekly market auctions for the different reserve products. We will consider capacity markets similar to the markets in Norway today, with *LFC* markets included, but without seperation between *FNR* and *FDR*, i.e one type of primary control. We assume here that the primary control capacity market clears first for several specific obligation periods during the coming week, and that the product is symmetric, meaning that the payment is per MW of primary control capacity in both directions. The secondary control capacity market clears second with the same obligations periods as for primary control, bids are not unit(station) specific and there exists separate products for each regulation direction. The tertiary control capacity market clears for one obligation period(the whole week) with separate products for each regulation direction. The spot markets clears in every hour during the week.

To get the symmetric primary control market modeled correctly some changes must be made in the model. The results from the previous optimizations would not have changed though since the primary control obligations for the 'producer' is symmetric. To model payment for symmetric supply we replace the price parameters for up and down supply with one price parameter for primary control. We do the modeling here for both types of primary control in Norway, even though we will just consider one type and only use the *FDR* variables:

Λ_{fnr}	–	FNR capacity price for the planning period (NOK/MW)
Λ_{fdr}	–	FDR capacity price for the planning period (NOK/MW)

We also need new variables to represent the symmetric supplies:

fnr_{tot}^{symm}	–	FNR symmetric capacity supply for the total planning period (MW)
fdr_{tot}^{symm}	–	FDR symmetric capacity supply for the total planning period (MW)

The objective function changes to:

$$
\begin{aligned}
max\text{: } & \Lambda_{fnr} \times fnr_{tot}^{symm} + \Lambda_{fdr} \times fdr_{tot}^{symm} \\
& + \Lambda_{lfc}^{+} \times lfc_{tot}^{+} + \Lambda_{lfc}^{-} \times lfc_{tot}^{-} + \Lambda_{rk}^{+} \times rk_{tot}^{+} + \Lambda_{rk}^{-} \times rk_{tot}^{-} \\
& + \sum_{g \in G} \sum_{t=1}^{T} \left[\Lambda_{spot_t} \times y_{g,t} - C_{start_g} \times start_{g,t} - VV_g \times q_{g,t} - c_{\delta_{g,t}} \right]
\end{aligned}
\tag{6.1}
$$

Constraints 4.34-4.37 are replaced with:

$$fnr_{tot}^{symm} \leq \sum_{g \in G} fnr_{g,t}^{+} \qquad \forall\, t = 1..T \tag{6.2}$$

$$fnr_{tot}^{symm} \leq \sum_{g \in G} fnr_{g,t}^{-} \qquad \forall\, t = 1..T \tag{6.3}$$

$$fdr_{tot}^{symm} \leq \sum_{g \in G} fdr_{g,t}^{+} \qquad \forall\, t = 1..T \tag{6.4}$$

$$fdr_{tot}^{symm} \leq \sum_{g \in G} fdr_{g,t}^{-} \qquad \forall\, t = 1..T \tag{6.5}$$

We assume here that the producer is a pure price-taker on all markets.

So the first market is the primary control capacity market. The model is run several times for chosen bid prices for this market with price forecasts for all the remaining markets(secondary,tertiary, spot) that may influence the primary control bid. With several products for specific obligation periods during the week(e.g. Monday-Friday 2000-2400) it is important that the price forecasts for the other markets are for the same periods. This is natural when products in other markets are split into the same(secondary) obligations periods. Shorter periods that can be added to match the relevant obligation period is also natural since the price forecasts of the different shorter periods can be represented in the model in much the same way that the single hour obligations of the spot market is represented. For the tertiary reserve market where the price is given for a longer obligation period it would be more difficult, but it would have severe consequences for the bids if the price forecast isn't representative for the relevant obligation periods as any bad price forecast would be. As an example we take a look at table 5.10. We see that the required compensation to fulfill the tertiary up-regulation capacity demand stems from hour 1 and 2. In hour 3,4 and 5 there is a surplus of supply. The price forecast used for primary control bids in an auction that spanned the hours 3,4 and 5(the shorter period) should be the part of the price needed to fulfill the tertiary up-regulation capacity demand for all the hours(the longer period) that stems from the hours in the shorter period(zero in this case). When an obligation is used instead of a price forecast the correct obligation would of course have to be used for the relevant periods. With this in mind it could be practical to clear the weekly market with the longest obligation period first since the obligation is the same for every hour while the contribution to the capacity price changes from hour to hour. This makes it more complicated to split an expected capacity price for a longer period into shorter periods.

After the primary control capacity market has cleared, the producer's obligations are known and this is used as an input when bidding for the next reserve type together with the price forecasts for remaining markets. The next reserve type is the secondary control reserves(LFC). Here we have separate products for each regulation direction(up and down). These two products are not only competing for capacity with other reserve types and the spot market, but also with each other. So prices or obligations for one of the products influence the bids for the other product. This means that auctions for these products must be cleared sequentially too. The obligation from one product must be known before calculating bids for the other. If the auctions were simultaneous and a producer used this method with a price forecast for one product when bidding for the other, the result could in worst case be physically infeasible for the producer. This is because price forecasts can't be exact per definition, and e.g. with a clearing price above the forecast for both products a producer could in worst case receive obligations that exceeded his total available capacity. This is the case for all competing products in the same obligation period, and one product must be cleared before calculating bids for the next. That price forecasts are not exact is not a problem with regard to feasability when all products clear sequentially.

With the primary and secondary control capacity markets cleared, the bids for tertiary control reserve capacity can be calculated with the same procedure. Bids for up- and down-regulation tertiary reserves will probably not influence each other for any units in a realistic power system with realistic demand and prices, but it may in theory so these auctions should also be sequential when using this method. Assuming that the spot market always clears last, i.e. after all the reserve markets, spot market bids would just be based on the marginal production costs while also accounting for the unavailable production capacity and/or forced production of the reserve obligations.

The elegant property of the procedure is how the total profit at all times is maximized ensuring optimal allocation of capacity. The model allocates capacity to the markets where this capacity achieves the highest profit. Capacity will be allocated to bids when the bid price gives a higher profit for this capacity than for any of the remaining markets according to the price forecasts. So opportunity costs for all markets are accounted for in the bids in addition to the direct costs and characteristics of the different products.

We will below use the model to illustrate bids on the different markets from a producer owning and operating a set of generating units.

6.1 Model setup

The obligation period we will consider on all the markets is 20.00-24.00 from Monday to Friday. This means that there is 4 spot markets clearings each day for 5 days in the obligation period giving a total of 20 hours. The deterministic spot price forecast we use here is equal to the system spot price in these hours on Nord Pool for week 45 in 2011. Figure 6.1 shows the prices for the 20 hours. Each day is 4 hours and we see that the prices typically fall towards the last hour each day and jumps up to the first hour the next day. This reflects the typical demand characteristics of the spot market in the Nordic countries with the demand at 20.00 being larger than the demand at 24.00.

Price forecasts for the other markets can be seen in table 6.1. A price forecast for primary control capacity reserves is not needed since it is the first market. The price forecasts here are not based on any real prices and are arbitrary other than that the likely correlation between prices are considered to some extent. But we use a price above zero for all markets, except for down-regulation manual reserve capacity market.

The set of generating units is based on real units, and 7 units with different characteristics are used. Some of these units is really part of a station with several units, but we will only include one unit from each station. Parameters used for the different units can be seen in table 6.2. We ignore start-up costs. The droop setting costs are adjusted according to the size of the unit with basis in the largest unit(SyS). This is because this cost is assumed to be a wear and tear

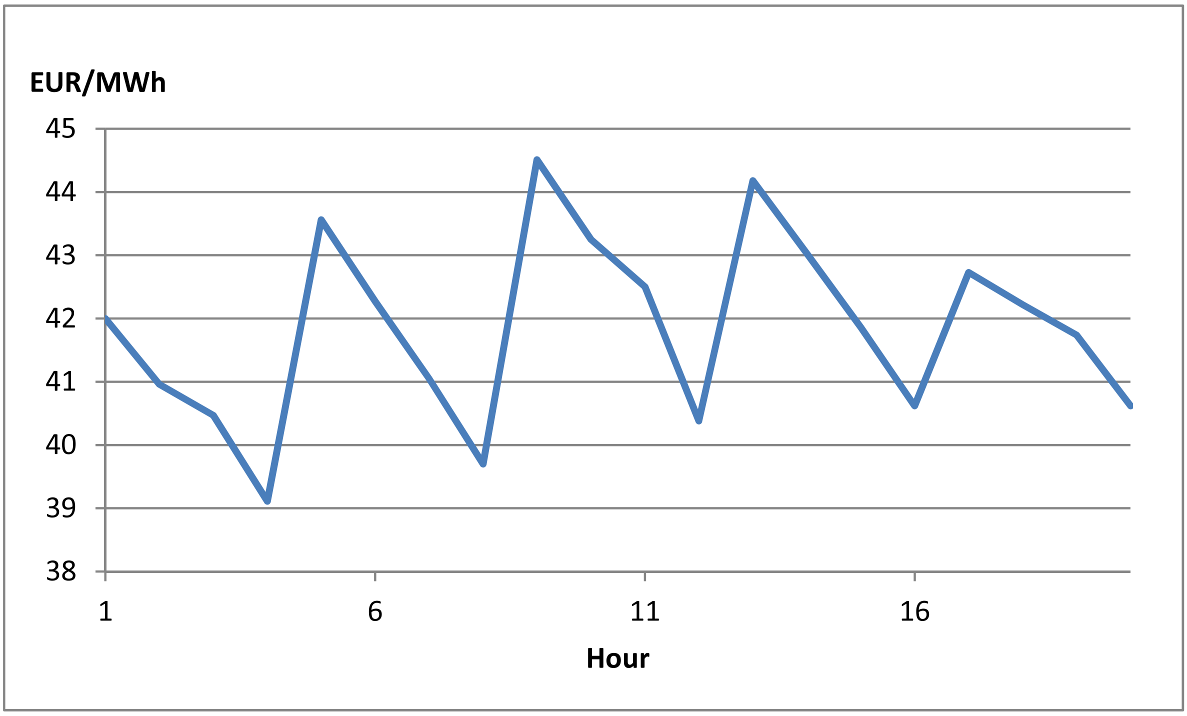

Figure 6.1: Spot price forecast

Table 6.1: Price forecasts for the relevant reserve capacity markets

Market	Forecast (EUR/MW)	Market	Forecast (EUR/MW)
LFC^+	40	RK^+	20
LFC^-	5	RK^-	0

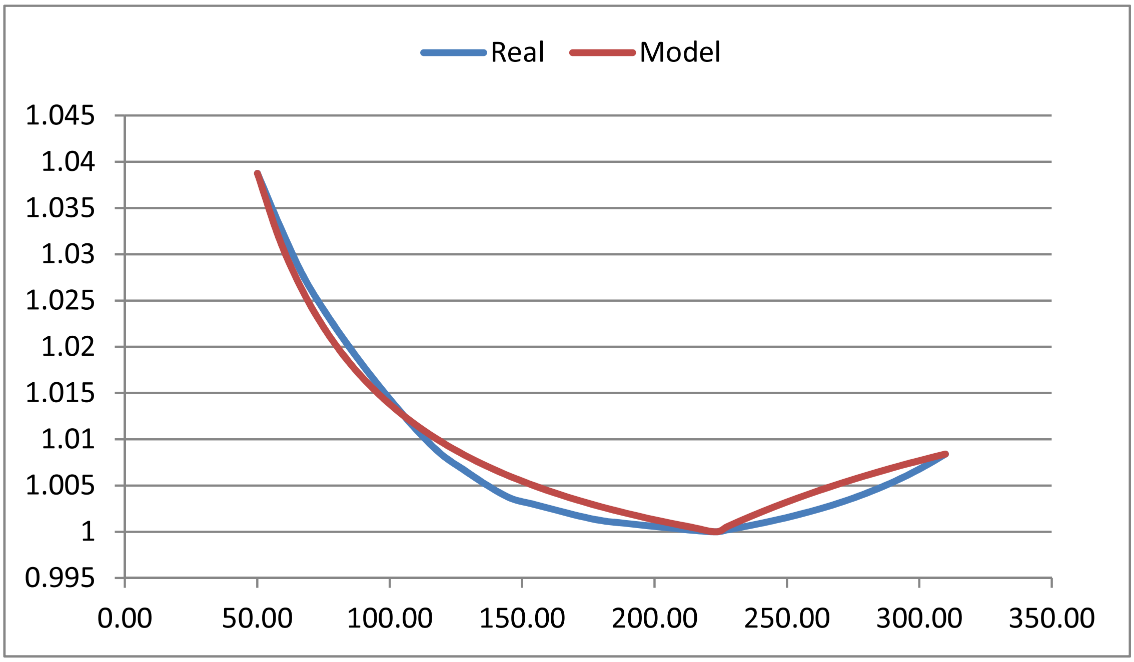

Figure 6.2: Relative water discharge

cost and is related to the investment costs of units. Only 2 segments are used for the PQ-curves due to computational considerations. Figure 6.2 shows the relative water discharge comparison for unit *SyS*. The actual *best-point* of each unit is included in the table. The water value for each unit is based on real water values from Statkraft in the relevant week.

Table 6.2: Unit parameters

Unit	**Y_min (MW)**	**Y_max (MW)**	**Best-point (MW)**	**PQ_min (MWh/h)**	**Th_min**	**Th_max**	**C_st (EUR)**	**VV (EUR/MWh)**
Adam	15	25	22.07	15.55	0.0833	0.5	0.81	41.9
Aura	3	29	24.40	3.85	0.0833	0.5	0.94	34.9
Bjol	13	89	65.96	13.21	0.0833	0.5	2.87	40.2
Gry	10	143	95.31	11.19	0.0833	0.5	4.61	46
Leir	58	114	97.90	60.22	0.0833	0.5	3.68	39.1
Mar	5	36	30.34	5.75	0.0833	0.5	1.16	32.7
SyS	50	310	223.25	51.99	0.0833	0.5	10.00	44.50

We will use the simplified version for down-regulation reserves that ignores the ability to shut down a unit for manual down-regulation reserves. This means that there is no difference between manual and spinning down-regulation reserves, but this simplification doesn't matter when the capacity price for down-regulation manual reserves(RK^-) is zero. It basically means that there is no capacity market for (RK^-) to be considered. The primary control reserves consist of only one type(FDR) as mentioned.

6.2 Results and discussion

First we will look at some of the impact unit characteristics other than the water value(resource cost) has on bidding and supply of capacity reserves. As an example we consider the unit *SyS*. *SyS* has minimum production(Y_{min}) of 50 MW and maximum production(Y_{max}) of 310 MW. This means that the unit has the ability to supply from zero to $Y_{max} - Y_{min} = 260$ MW of spinning reserves. In hours where the unit does not want to produce anything(low spot price), the 'fixed' cost for spinning reserves that is decoupled to the supply arises and increased supply lowers the required compensation per MW, i.e. a falling supply curve for the unit. Direct costs, e.g. the droop setting costs for primary control, may offset this and the capability for primary control supply may anyhow be below the available capacity(260 MW), but any profitable utilization of the remaining capability, e.g. as secondary or tertiary up-regulation reserves, would in this case lower the required compensation per MW also for primary control. This means that it is the relation between (Y_{max}) and (Y_{min}) rather than the actual value of (Y_{min}) that is most crucial for a unit's cost of supplying up-regulation spinning reserves assuming that the full capacity of a unit can be sold. This relation is also crucial for the difference between a unit's cost of up-regulation spinning reserve supply and up-regulation manual reserve supply(RK^+). Unit *SyS* may supply 310 MW of (RK^+), so the difference will not only be made up of the 'fixed' costs, but also the increased total income for a given price coming from the larger volume. Comparing unit *SyS* with unit *Gry* we see that the relation between (Y_{min}) and (Y_{max}) is 16% for *SyS* and 7% for *Gry*. Lower is better. With everything else being equal between the units it means that *Gry* is better suited for e.g LFC^+ supply and that *SyS* is better suited than *Gry* for RK^+ supply relative to LFC^+ supply. This means that there would exist a price level for LFC^+ and RK^+ where *Gry* would maximize its profits with LFC^+ supply while *SyS* would do the same with RK^+ even though everything else apart from Y_{min} and Y_{max} were equal.

The relation between (Y_{max}) and (Y_{min}) is important also for down-regulation spinning reserves for the same reasons and the unit with the lowest cost of supply may change with varying spot prices also for down-regulation, even though an individual unit always has lower costs with lower marginal production costs and lower spot prices can only lead to higher costs of supply for the market as a whole.

The efficiency curves of different units will also have an impact on how units will rank on different markets and on the bids themselves. The efficiency of different production levels compared to the efficiency at *best-point* becomes important whenever a unit may achieve a profit in the spot market. We see from table 6.2 that the production costs per MW for *SyS* is 44.50 EUR at *best-point*, while being 46.22 EUR at the minimum production level. This is calculated using the efficiency at Y_{min}. We assume an hour with a spot price of 46.50. The marginal production cost is lowest at the *best-point* with 44.50 EUR, so the required compensation for any type of up-regulation reserve related to the spot market would increase with increasing supply up to a compensation of 2 EUR/MW for a supply of Y_{max} - *best-point* MW(86.75 MW). Increasing the up-regulation reserve supply marginally from the *best-point* also increases the required compensation per MW since the efficiency again drops, but for RK^+ supply it would be possible to supply Y_{max} MW (310 MW) without increasing the compensation per MW since the total profit would still be the same.The required compensation for maximum RK^+ supply would actually be lower than 2 EUR/MW since the full unit capacity can be sold without any changes to the direct costs like for the spot market. For spinning reserves it is a requirement with spot production, so if the unit should supply the maximum capability of 260 MW for up-regulation spinning reserves(LFC^+), the spot production would be sold with a production cost per MW of 46.22 EUR instead of 44.50 EUR. This gives a higher required compensation per MW of LFC^+ supply since the total profit is reduced compared to spot production at *best-point*. The calculation would be a total profit of $2 * 310 = 620EUR$ for maximum RK^+ supply or spot production at *best-point* plus the rest as reserves with a price of 2 EUR/MW for reserves. With 260 MW as LFC^+ supply the compensation per MW LFC^+ would have to be $(620 - 50 * (46.50 - 46.22))/260 = 2.33$ EUR/MW for the total profit to be equal. So we see that the spinning requirement creates an extra cost also here, and this extra cost would be lower for a unit the better the efficiency at Y_{min} would be compared to the *best-point*.

In the last case we saw that LFC^+ supply for a unit has increasing costs with increased supply, so a unit wouldn't always want to increase its supply of up-regulation spinning reserves for a given price in those spot price situation as it would when no profits could be made in the spot market. For a unit bidding for and supplying LFC^+ for a period of several hours with varying spot prices the actual volume offered from the unit at the lowest price level(the lowest bid) would be a tradeoff between these two situations in the period. The maximum volume would be offered if costs from hours where the spot price is too low for the unit dominated, while a lower volume would be offered if the accumulated extra profits from the spot market with this lower volume exceeded the extra income from the higher volume in the reserve market.

6.2.1 Primary control capacity bids

Table 6.3 shows the bids for primary control capacity. The price column shows the price range that gives the same offered volume. The symmetric product means that the offered volume goes in both directions. E.g. the bid for 8 MW means 8 MW down-regulation and 8 MW up-regulation. Any capacity that qualifies as reserves for up-regulation primary control for the total period may here be directly substituted with tertiary up-regulation reserves(RK^+) and/or secondary up-regulation reserves(LFC^+), so the bids would in this case never go below 40 EUR/MW which is the forecast for LFC^+. A lower price than this for primary control reserves means that it would be more profitable to save all up-regulation spinning capacity for use in the future LFC^+ market where it could be sold for 40 EUR/MW. The same can be said for down-regulation primary control reserves which may be directly substituted for tertiary and/or secondary down-regulation reserves(RK^- and LFC^-). The price forecast for LFC^- is here 5 EUR/MW, so this actually means that the bids for the symmetric primary control product would never go below $40 + 5 = 45EUR/MW$ in this case.

Table 6.3: Symmetric primary control bids

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0-44	0	128-130	218
45	8	131	226
46	49	132-193	230
47-53	96	194-247	234
54-67	102	248-276	240
68-101	105	277-278	242
102-120	114	279-280	247
121-124	117	281-290	254
125-127	215	291-	260

Table 6.4: Primary control bids when the spot market is the only other market

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0	0	34-72	105
1-5	3	73-81	110
6	6	82-85	218
7-12	16	..	..
13-14	23	..	..
15-25	26	..	..
26-27	39	..	..
28	42	..	..
29-33	52	..	..

We see in table 6.3 that the bids starts at 45 EUR/MW, which means that the offered volume replaces profitable LFC^+ and LFC^- supply. We will assume that the market clears with a price of 50 EUR/MW. This gives an obligation of 96 MW for the producer. By taking a look at tables A.1 and A.2 in appendix A we see that the supply is supposed to come from the same combination of units and commitment in each hour during the period, but with a different unit commitment for each direction. If only the spot market was considered it is likely that some capacity could have been supplied for a lower cost by changing the commitment in some hours. This is due to the variation of the spot prices. Table 6.4 shows the bids without a price for any of the other reserve capacity markets. The bid for 50 EUR/MW shows a bit higher volume and tables A.3 and A.4 in appendix A shows the calculated unit commitment in each hour for this bid. We see that the volume for this price is supplied by changing the committed units in some hours. With a profitable price(or obligation) for the other markets this type of changing the committed units from hour to hour is discouraged. Take as an example RK^+ supply where the best unit commitment for a given price and amount doesn't change with varying spot prices during a period. The unit SyS sells his whole capacity as RK^+ with the prices given here. Now if capacity for up-regulation primary control reserves(FDR^+) is supplied from this unit in e.g. only one hour or a number of hours shorter than the full period which is the case is in table A.3, it means that the unit can't supply the full RK^+ capacity in each hour and a lower amount of RK^+ must be sold for the whole period. This does not maximize the profits, and the effect is that the supply of primary control reserves over the period is more likely to come from the same unit commitment in each hour. All such considerations are taken care of by the optimization.

Another important factor that discourages different commitments in each hour is the size differences of units($Ymax - Ymin$). The best commitment for the supplying unit/units in a specific hour is often maximum supply, and with large size differences the optimal volume to be offered for the whole period is most likely not possible to supply from different units in different hours. Low variation of the spot price(demand) during the period will of course also contribute to the same unit commitment for the reserve supply in each hour.

It also shows how important the price forecasts for the other reserve markets can be with this method. To illustrate this we can again take a look at the optimization in section 5.1.1. Assume that a producer with the units in that optimization is bidding for symmetric primary control reserves or for up-regulation spinning reserves in general for the 5 hour period shown in table 5.1. The market situations are such that the producer optimally should get the market commitments shown in the optimization. Without a price forecast for the other reserve markets(manual up-regulation reserves and down-regulation reserves) the accumulated costs over the hours that is the basis for the bids would for the lowest bid volume come from unit 10 in hour 1 and unit 1 in hour 5. Those units should optimally be used for other markets, so the accumulated costs would be too low and the bid would thus be priced too low. With correct price forecasts those units would have been 'reserved' for other markets and using them as up-regulation spinning reserves decreases the total profit in the model and ultimately gives correct costs as basis for the bids.

6.2.2 Up-regulation secondary control capacity bids

Table 6.5 now shows the bids for LFC^+ with the obligation of 96 MW for primary control. The up-regulation capacity qualified as LFC^+ for the period is directly substitutable with RK^+ so no bid will be below 20 EUR/MW. If we assume the same clearing price as the price forecast(40 MW/EUR) the obligation for LFC^+ becomes 76 MW, which is the offered volume for a price between 21 and 40 EUR/MW. If we now prepare the bids without the primary control obligation we can see the effect the primary obligation has on the LFC^+ bids. Table 6.6 shows the bids without the primary control obligation.

Table 6.5: LFC^+ bids

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0-20	0	84-136	369
21-40	76	137-169	374
41-46	336	170-179	384
47	349	180-205	389
48	354	206	396
49-83	360	207-	400

Table 6.6: LFC^+ bids without primary control obligations

Price (EUR/MW)	**Volume (MW)**
0-20	0
21-32	23
33-35	39
36-40	172
41-48	432
48-91	485
..	..
..	..
..	..

We see that the offered volume without the primary obligation is much lower for prices between 21 and 35 EUR/MW. The reason for this is the 'fixed' costs originating from the minimum production level of a unit. These costs are accumulated for each hour during the period. Primary control capability for a unit is limited by the droop setting and will normally be limited to an amount lower than the available capacity at minimum production($Ymax - Ymin$). This means that a unit that must be spinning throughout the period due to primary control obligations can supply available capacity as LFC^+ without accumulating these 'fixed' costs. For this capacity the difference between RK^+ and LFC^+ disappears completely since the units supplying the capacity are now known to be spinning. Due to this effect we see in tables 6.5 and 6.6 that a larger volume is offered as LFC^+ for a lower price with the primary control obligation. For a price above 36 EUR/MW a larger volume of LFC^+ is offered for the bids without a primary control obligation. This is because that price makes LFC^+ supply more profitable than the other markets for a larger part of the capacity without relying on already committed spinning units. The primary control obligation is taken from this capacity and we see that $172 - 76$ equals 96 MW.

The big jump in the offered volume at 41 EUR/MW is just a coincidence. That price is exactly where it becomes more profitable for the unit SyS to switch from RK^+ supply to LFC^+ supply and has actually nothing to do with the price forecast for LFC^+.

6.2.3 Remaining markets

Assuming the same clearing price for LFC^+ as the price forecast the obligation becomes 76 MW. By also assuming the same clearing price as the price forecast for the following markets we get bids for each market shown in tables 6.7-6.9.

Table 6.7: LFC^- bids

Price (EUR/MW)	**Volume (MW)**
0	0
1-45	55
46-74	64
75-87	191
88-90	277
91-92	314
93-	324

Table 6.8: RK^+ bids

Price (EUR/MW)	**Volume (MW)**
0	0
1	231
2	234
3-12	310
13-29	335
30-	335

Table 6.9: RK^- bids

Price (EUR/MW)	**Volume (MW)**
1-	0

Table 6.10: Final reserve obligations

Market	Obligation (MW)	Market	Obligation (MW)
Prim	96	Rkup	335
LFCup	76	Rkdown	0
LFCdown	55		

The final reserve obligations can be seen in table 6.10. This is exactly the same allocation of capacity that was assumed when capacity was reserved for future markets for the bid at 50 EUR/MW for primary control capacity reserves. This is natural since we have cleared the markets with the price forecasts.

We see here is that all the capability for reserve supply has been sold for the given prices, so there is no freedom left for the spot supply. There is no capacity left for RK^- either as seen in table 6.9, since no price was expected in this market and all the capacity was sold in previous markets. The spot production would have to be the same in every hour during the period to fulfill all the reserve obligations, so the bid in the spot market for the set of units have to be this exact amount regardless of the price. If the price forecast for the spot prices were exact too, the capacity allocation resulting from the bids would give the maximum possible total profit for the producer owning the set of units.

Changed market order

Changing the order of the markets, e.g letting the secondary control markets be the first markets, will theoretically not change anything. Table 6.11 shows the bids for LFC^+ when the primary control market is included with a price forecast of 50 EUR/MW.

Table 6.11: Bids for LFC^+ when it is the first market

Price (EUR/MW)	Volume (MW)	Price (EUR/MW)	Volume (MW)
0-30	0	48-91	485
31-40	76	..	..
41-43	330	..	..
44	363	..	..
45	414	..	..
46-47	432	..	..

We see that the volume offered for 40 MW/EUR is the same as before.

Chapter 7

Multi-Scenario model

7.1 Price uncertainty

Prices of future markets are uncertain and may have a number of possible outcomes. The optimizations in the last chapter that illustrated the bidding procedure used a deterministic model, where the price forecasts represented the expected value of the uncertain prices. This type of model does not consider the effect the variation of possible price outcomes has on a unit's valuation of future markets. A deterministic model does actually not consider uncertainty at all since it assumes everything to be known.

Consider a unit acting on the spot market. Whenever the spot price is above his marginal production costs he gets a profit, and whenever the spot price is below his marginal production costs he has the option to not produce and thus avoid a negative profit. Using the expected value of the uncertain prices as a forecast will generally understate the value of this optionality for the unit and could thus understate the expected profits[4]. As an example we can again take a look at unit SyS with a marginal production cost at *best-point* of 44.50 EUR/MW used in the bid illustration. With the price forecast from figure 6.1 the unit would have zero expected profits from the spot market in this period since the spot price is given as below(or equal to) the marginal production cost at best point for all hours. Assuming that the unit couldn't achieve a profit in any of the down-regulation or spinning reserve markets it means that he would be able to offer RK^+ volume without compensation. But the spot prices in the period are uncertain, and any probability for the spot price outcome to actually be higher than the forecast and above the marginal production costs in any hour means that the expected profits in the spot market for the period would be above zero. So the unit would need a compensation for RK^+ capacity that takes this probability into account. A similar type of optionality effect also exists between the different markets, since several future markets for the same capacity creates even more options.

To illustrate this we consider a unit that is bidding for one of the up-regulation capacity reserve markets(the first market) that clears for a specific period. There are two future markets, the spot market and another up-regulation capacity reserve market(the second market) that is an alternative to spot supply, e.g RK^+, meaning that capacity supplied for this market has zero profits from the spot market in the period. The first market is an alternative to both these markets. The other capacity reserve market clears for the same specific period and before the spot market. The unit has expected profits of 35 EUR/MW from the spot market for the total period, accounting for all price uncertainty. The second market has four possible price outcomes with equal probability that gives a profit for the unit in this market of respectively 50, 40, 35 and 25 EUR/MW. Assuming no direct costs for the unit in this market they represent the actual prices. So the expected value of the prices in this market is $(50{+}40{+}35{+}25)/4 = 37.5$EUR/MW. Using just this single price as a price forecast gives the correct expected profits of 37.5 EUR/MW for the unit in this market, but it does not give the unit's correct expected profits for the future markets combined which should be considered for the bids in the first market. When the price outcome for the second market is below 35 EUR/MW it is better for the unit to save the capacity for the spot market since his expected profit in the spot market is 35 EUR/MW. So the actual future expected profit for the unit is $(50 + 40 + 35 + 35)/4 = 40$EUR/MW. Using the expected value of the price as a price forecast for the second market could thus understate the expected profits from future markets.

Understating the value of future competing markets leads to too low bids in previous markets, but the severity of the effects above with a deterministic approach depends on the variance of the possible price outcomes. If the uncertainty is low so that the forecast is always close to the actual price the method may still provide good bids.

7.2 Multi-scenario

A multi-scenario deterministic approach for the MIP-model where the price forecast in each scenario represents different price outcomes is suitable to capture effects of uncertain prices in future markets and the option value this creates for the units. With scenarios that perfectly represents the statistical properties of the uncertain prices the expected profits and value of the future markets can be calculated. The model is still deterministic for each scenario though, with the general issues this presents.

The complication is all the different markets. While a multi-scenario deterministic approach might be fine for all the markets independently[1], it is difficult and probably not so good to have scenarios with prices across all markets. All market prices are correlated with each other to differing degrees, but the market prices of previous markets are not correlated to specific outcomes of the prices in future markets. They are rather correlated to the total expectation of the future uncertain prices. So the price uncertainty in each market is independent of the uncertainty of the other markets. Having a multi-scenario deterministic description of the spot market with stochastic links between the different markets is a possibility. It is the many time periods of the spot market that is the biggest challenge, but the amount of stochastic periods increases with the amount of future markets.

We will here simplify by saying that the only future market with price uncertainty is the spot market. This is actually often the case in Norway today, when FNR^+ is the only reserve capacity market with prices(LFC markets not implemented). The price uncertainty of future well-functioning reserve capacity markets shouldn't in theory be very large anyway if they clear at about the same time. The demand is known and the expectation of the future markets should not change much between the clearing of the different reserve capacity markets.

To implement multiple scenarios for the spot market in the model we need a new index:

z – Spot price scenario z over the planning period

Some new parameters are also needed:

[1] It certainly is for the reserve capacity markets, since they only have one time period

Z	–	Number of spot price scenarios
PX_z	–	Probability for spot price scenario z

All the variables that are indexed over the time periods t must also be indexed over each spot price scenario z.

The objective function is changed to:

$$\begin{aligned} max\text{:}\ & \Lambda^+_{fnr} \times fnr^+_{tot} + \Lambda^-_{fnr} \times fnr^-_{tot} + \Lambda^+_{fdr} \times fdr^+_{tot} + \Lambda^-_{fdr} \times fdr^-_{tot} \\ & + \Lambda^+_{lfc} \times lfc^+_{tot} + \Lambda^-_{lfc} \times lfc^-_{tot} + \Lambda^+_{rk} \times rk^+_{tot} + \Lambda^-_{rk} \times rk^-_{tot} \\ & + \sum_{z=1}^{Z} PX_z \times \left[\sum_{g \in G} \sum_{t=1}^{T} \times (\Lambda_{spot_t} \times y_{g,t} - C_{start_g} \times start_{g,t} - VV_g \times q_{g,t} - c_{\delta_{g,t}}) \right] \end{aligned} \tag{7.1}$$

The volume allocated as reserve capacity for the total period limits the units' options in the spot market for each scenario, so the allocated volume gives the optimal amount for all the scenarios combined.

Bids with the multi-scenario deterministic model will in the following be illustrated and compared to bids with the single-scenario deterministic model.

7.3 Model setup

We will look at bids seperately for RK^+ and LFC^+ where we assume no obligations and/or no price in any of the other capacity markets. The product period is the same as earlier with Monday-Friday 2000-2400(20 hours). This is usually hours with medium high spot demand, at least in Norway, so there should normally be enough capacity both in and out of production giving no price(or very low) for manual up-regulation reserves and all down-regulation reserves for the period. Up-regulation primary control reserves would probably have some capacity price, both due to the direct costs of primary control and the characteristics of up-regulation spinning reserves, but we assume here for simplicity that the producer in question has no obligations from this market. So the only active markets are either RK^+ or LFC^+ and the spot market.

The units owned by the producer is the same as earlier with the same parameters as in table 6.2.

Statkraft does not make multi-scenario spot price forecasts as a standard, so the scenarios used here are generated with basis in the single-scenario price-forecast made by Statkraft each day and week. The spot price forecasts by Statkraft are made with fundamental models, so these forecasts are theoretically a bit different than the expected value forecasts talked about earlier. The fundamental forecasts basically find the most likely scenario based on expected supply and demand in the market. This can be differerent than the expected value of the prices since the price uncertainty in the spot market can have different characteristics for different load situations. But the principles of price uncertainty are the same and the uncertainty related to these forecasts should be described as good as possible.

To generate the multi-scenario forecast we take the spot price forecast from Statkraft at the time when the weekly capacity markets are assumed to clear. These forecasts are compared with the actual spot prices for that week and the difference between the two for each hour is

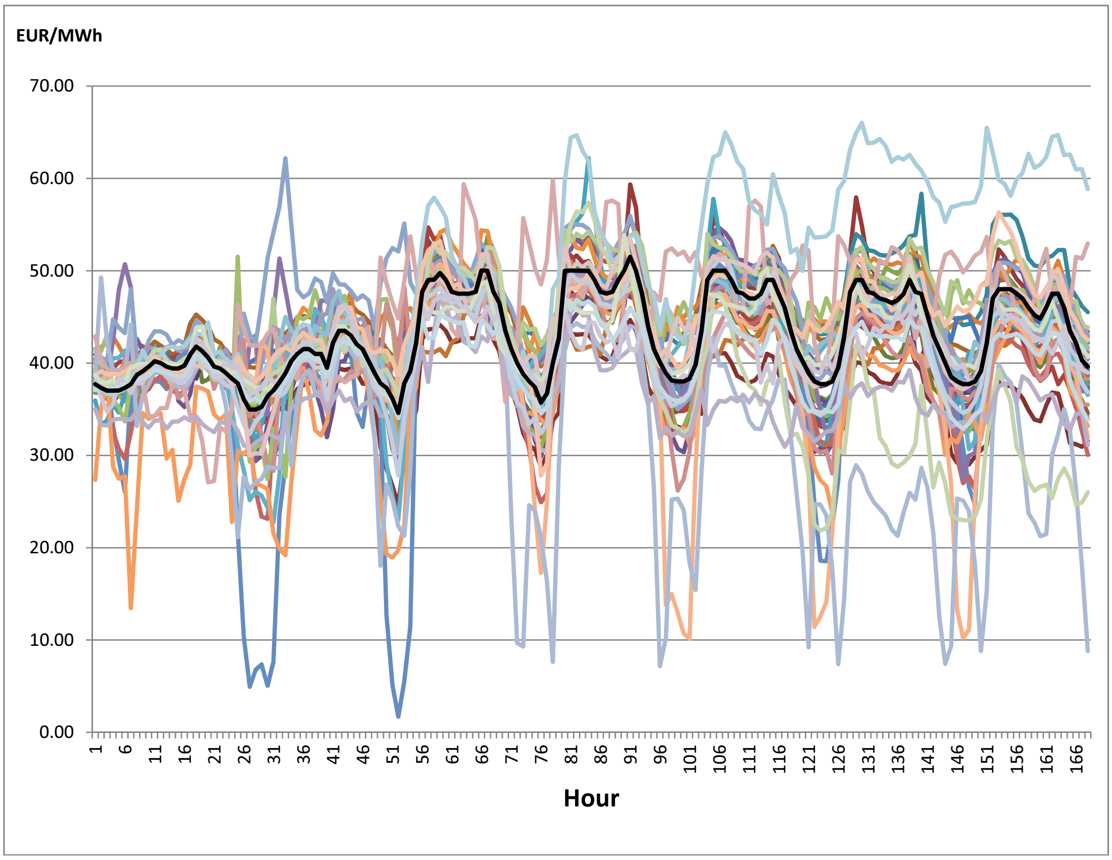

Figure 7.1: Spot price forecast

used as a scenario. Doing this for many weeks gives many scenarios and a good representation of the spot price uncertainty related to the forecasts will at some point be captured. This has been done for the Nord Pool system price for the 45 first weeks of 2011 giving 45 scenarios in addition to the actual forecasted scenario in a week. Figure 7.1 shows the scenarios for a whole week(168 hours, Saturday to Friday). The price forecast for week 45 in 2011 is the base scenario here and is the black line in the figure.

The forecast is done just before hour 1 and it can be seen that the uncertainty of the prices increases with time. This is expected. All scenarios generated here will not be used in the optimizations mainly due to calculation time limitations since the calculation time increases with each new scenario, but also because all the scenarios don't really represent the uncertainty for the situations we will optimize for later. So some of the very low price scenarios are removed since they are generated in summer weeks with very low load where the uncertainty isn't necessarily representative for more normal weeks. Also removing some random scenarios brings the number of scenarios used here to 20. Figure 7.2 shows the scenarios for the period Monday-Friday 2000-2400. Table 7.1 and the black line in figure 7.2 shows the prices for the base scenario, which is the price forecast that is used for the single-scenario model optimizations and the reference scenario for the multi-scenario model optimizations.

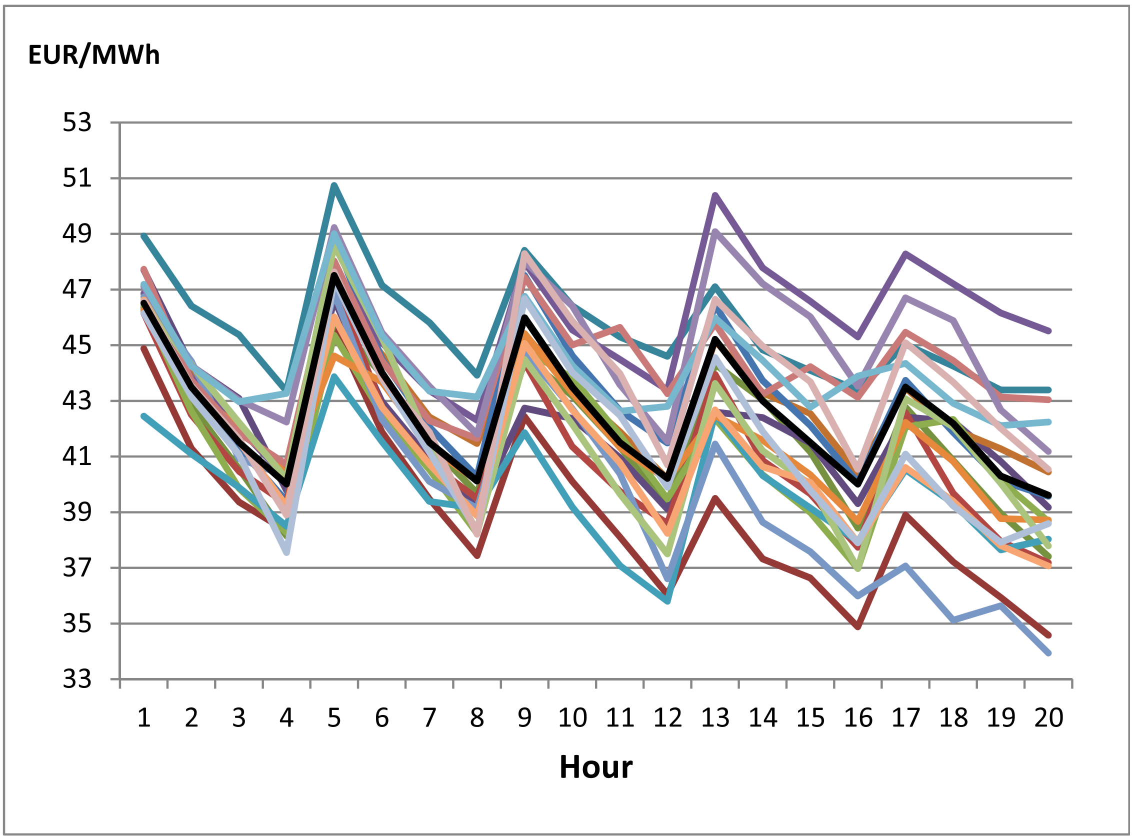

Figure 7.2: Spot price forecast

Table 7.1: Base scenario(single-scenario prices)

Time period	**Spot price (EUR/MW)**	**Time period**	**Spot price (EUR/MW)**
1	46.51	1	41.51
2	43.5	2	40.21
3	41.51	3	45.21
4	40.01	4	43
5	47.51	5	41.51
6	44.02	6	40.01
7	41.51	7	43.5
8	40.12	8	42.19
9	45.99	9	40.3
10	43.5	10	39.61

7.4 Results

7.4.1 RK^+

Table 7.2 shows bids for RK^+ with the single-scenario model, while table 7.3 shows RK^+ bids with the multi-scenario model. Comparing the bids shows that the multi-scenario model indeed gives lower volume for some prices. 230 MW is e.g. offered for a price of 3 EUR/MW with the single-scenario model, while the same volume requires 5 EUR/MW with the multi-scenario model. The units supplying this volume are the units with the highest production costs and these units have a higher expected profit from the spot market in the multi-scenario model than the single-scenario model. This is because the scenarios with higher prices than the single(base) scenario give higher unit profits, while the scenarios with lower prices often give the same profit as the base scenario since unit profits in the spot market alone are non-negative. This increases the expected profits. For higher prices we see that this tendency stops, and for the highest prices it is actually the other way around with the single-scenario model requiring higher prices for the same volume. The new volume that is offered for high prices comes from units with low production costs, so low that they basically achieves a profit in the spot market for all scenarios in all hours. The optionality effect is not present for these units and the difference in the bid prices for these units between the two models would come from the distribution differences of the multiple scenarios compared to the single scenario. The single-scenario price forecast is forecasted by Statkraft using fundamental models, and it is obvious that the multiple scenarios used here that are generated from the actual prices in selected weeks compared with these forecasts are weighted a bit on the downside compared to the single-scenario forecast(base scenario).

Table 7.2: RK^+ bids, single-scenario model

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0	0	45-48	517
1-2	48	49-69	583
3-7	230	70-146	681
8-10	453	147-153	686
11-22	456	154-189	710
23-25	479	190-197	716
26-44	501	198-	746

7.4.2 LFC^+

For spinning up-regulation capacity reserves like LFC^+ it is not so straight forward as with RK^+ or the other types. Down-regulation reserves will be the opposite of RK^+ with the scenarios above the expected prices creating a type of optionality effect and increasing the cost of supply. Whenever the spot prices goes above the marginal production costs for a unit the cost for down-regulation reserves is zero and further increasing the spot prices can't reduce the cost further[2]. So the lower price scenarios increases the cost compared to the single-scenario while the higher price scenarios often will give the same cost(zero) which creates the same effect as for RK^+.

[2]Assuming no influence on the unit from up-regulation reserve prices

Table 7.3: RK^+ bids, multi-scenario model

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0	0	49-52	517
1-3	48	53-69	583
4	143	70-142	681
5-9	230	143-149	686
10-14	453	150-185	710
15-26	456	186-193	716
27-30	479	194-	746
31-48	501		

For LFC^+ the costs related to the spot market may come from both sides of the spot price. So scenarios with lower spot prices will decrease the costs for units where the expected spot price from the single-scenario forecast is already above the marginal production costs, but as soon as the spot price goes below the marginal production costs the costs will start to increase due to the required minimum production level. The same is the case for scenarios with higher spot prices where the costs decreases as long as the spot price is below the marginal production costs, but increases on the other side when the unit could have profitable spot production. So it would depend on the unit's distance to the expected spot price in addition to the variance of the uncertain prices. For units with production costs very close to the spot price it would mean that price scenarios on both sides of the expected price quickly gives increased costs unlike the other types where only one of the sides gives increased costs of supply, but with possible changing unit commitments in each scenario for the same bid volume the effect of each scenario can be hard to predict. The increased cost due to price uncertainty would probably be even larger for station specific bids.

Table 7.4: LFC^+ bids, single-scenario model

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0	0	50-56	435
1-6	3	57-81	485
7-13	16	82-85	488
14	26	86-118	495
15-16	149	119-127	526
17-18	220	128-146	536
19-24	225	147-179	540
25-29	409	180-189	562
30-44	419	190-215	567
45-49	432	216-	593

Table 7.4 and 7.5 shows bids for LFC^+ with the single-scenario model and the multi-scenario model. It can be seen that the multi-scenario model with this setup consistently requires a higher price for the same volume, which is the likely result for all realistic setups and price scenarios. It is here just the highest bid that has a lower price for the multi-scenario model. This is volume with low production costs, so the reasons are the same as for RK^+ with multiple

Table 7.5: LFC^{+} bids, multi-scenario model

Price (EUR/MW)	**Volume (MW)**	**Price (EUR/MW)**	**Volume (MW)**
0-7	0	67-68	474
8-12	3	69-83	485
13-14	5	84-89	488
15	26	90-120	495
16	81	121-132	526
17	136	133-156	536
18	209	156-175	540
19-21	214	176-177	552
22-25	220	178-181	557
26-28	225	182-189	562
29-34	398	190-212	567
35-51	419	213-220	583
52-59	435	221-	593
60-66	469		

scenarios being weighted a bit on the down side compared to the single scenario.

Chapter 8

Benchmarking

The optimal bid given under uncertainty is the bid that maximizes the expected profits for a producer and it is the bid that would give the highest profits over time. This bid is not the same as what the bid would be if the actual price outcome were known beforehand. So the bid that would have given the highest profit after the fact is not the same as the optimal bid given under uncertainty.

The optimal bid is of course hard to find and without perfect information for a given situation so that all uncertainties can be perfectly described it can't really ever be known. The challenge for the producer is to find a bidding strategy and bids that are as close to the optimal bids as possible so that the total profits over time can be maximized. To look at the ability of a deterministic MIP-model to give decision support for bidding in weekly reserve capacity markets we will benchmark some different bidding strategies against each other over a number of weeks.

The reserve capacity market in question is the LFC^+ market and just as for the bids shown in section 7.4.2 we assume that the only relevant future market is the spot market and that the producer has no obligations from previous markets. The set of generating units available for LFC^+ supply is the same as earlier(section 6.1.

The obligation period is the evening product for weekdays (Monday-Friday, 20:00-24:00), which is 20 hours and spot market clearings. We assume that the LFC^+ market clears on the Friday before, so it is about a week between the market clearing and the last obligation hour. The weeks that that will be tested against are the weeks 2 to 30(except week 17[1]) of 2011 and it is the system spot prices for these weeks at Nord Pool and Statkraft's forecasts for these prices that will be used in the model.

The price forecasts are taken from the day when the weekly capacity market(LFC^+) is assumed to clear. We assume for simplicity that the LFC^+ product clears for a price of 20 EUR/MW in every week. For other capacity markets it would be more natural to relate the clearing price in each week to the spot price forecast, but the LFC^+ price is in principle just directly correlated with the spot price in capacity constrained situations for the power system(up or down). We assume here that all or at least many units in the power system can supply secondary control so the clearing price would in unconstrained situations be independent of higher or lower spot prices in a week, but depend on the supplying units' production costs compared to the spot price. The evening hours optimized for here are neither low or high load hours in any of the weeks and it is plausible that the capacity price for LFC^+ should be quite similar from week to week. Bids are calculated with basis in the price forecasts in the same way as in section 6

[1]No price forecast was available at the desired day due to Easter holiday

and the chosen bids are then used in the model together with the actual spot price outcomes to look at the resulting profits for each week.

The water value of the units is based on real water values from Statkraft and are also taken from the day when the weekly capacity market clears for each week.

Four different bidding strategies will be compared. Strategy 1(Str1) emphasizes the spot market as the important market and is not interested in altering optimal spot commitments to provide capacity reserves, unless the price is for reserves is really high. This strategy prices the reserve supply out of the market and no volume is offered for 20 EUR/MW for any of the weeks. Strategy 2(Str2) uses the single-scenario MIP-model to calculate the bids, but recognizes that the bid volumes might be priced too low due to spot price uncertainty and adds 5 EUR/MW to each bid level. This means that the offered volume for 20 EUR/MW would be the amount the model offers for a price of 15 EUR/MW. Strategy 3(Str3) also uses the single-scenario model version to calculate bids and offers this volume without adjustments. Strategy 4(Str4) uses the multi-scenario model version to calculate bids and offer this volume without adjustments. The scenarios are generated as before with the single-scenario forecast for each week used as the base scenario. The strategies are summarized below:

Strategy 1 No offered volume

Strategy 2 Single-scenario model + 5 EUR/MW

Strategy 3 Single-scenario model

Strategy 4 Multi-scenario model

8.1 Results and discussion

Table 8.1 shows the results for each week. The magnitude of the objective function value(total profits) in different weeks is a bit misleading since some of the units in certain weeks have very low water values compared to the spot price level giving very high profits relative to the income in other weeks and the income from the reserve market. These units could in those cases just as well have been left out of the optimization since they are far from being able to supply reserves for 20 EUR/MW and their contribution to the total profits are the same for all strategies. The interesting result is the impact of the different bids and the comparison of the profits from the different strategies in each week and this is separate from the differences of the total profit between the weeks. A difference of 2 000 EUR between two strategies is just as important on top of a total profit of 5 000 EUR as on top of a total profit of 40 000 EUR here since the high total profit are randomly made up by irrelevant units. So the actual objective function value is meaningless and is not included in the table[2] Column *COMP* shows the profits in each week compared with strategy 1 meaning of course that the relative profits of strategy 1 is zero for all weeks. Column *BID* shows the offered and accepted bids for 20 EUR/MW and column *DIFF* shows a rough estimate of how the spot price outcome of the weeks were relative to the single-scenario price forecasts during the period.

In row *Total* it can be seen that strategy 2 gives the highest profits over the period, with strategy 1 performing the worst. That strategy 1 is by far the worst is quite natural. A demand and price for capacity reserves increases the total demand and opportunities for profit in a power system and should increase the producers potential profits. Not taking advantage of these

[2]It is included in table A.5 in appendix A if it should be of interest.

Table 8.1: Comparison of total profits between the different strategies.

Week	**Str1**		**Str2 SING+5**		**Str3 SING**		**Str4 MULT**		**DIFF**
	BID (MW)	**COMP (EUR)**	**BID (MW)**	**COMP (EUR)**	**BID (MW)**	**COMP (EUR)**	**BID (MW)**	**COMP (EUR)**	
2	-	-	0	0	132	-1 194	132	-1 194	LOW
3	-	-	5	-172	138	-608	136	-497	LOW
4	-	-	8	33	141	459	133	424	UNDER
5	-	-	0	0	133	387	133	387	UNDER
6	-	-	0	0	133	864	133	864	HIGH
7	-	-	133	872	469	2 104	133	872	OVER
8	-	-	133	1 487	469	2 627	146	1 534	OVER
9	-	-	136	789	396	929	146	764	UNDER
10	-	-	136	1 034	396	1 283	141	1 042	UNDER
11	-	-	127	171	311	-5 250	209	-1 297	HIGH
12	-	-	157	879	157	879	133	1 170	LOW
13	-	-	153	2 289	159	2 280	133	2 029	UNDER
14	-	-	138	313	214	75	133	687	LOW
15	-	-	0	0	209	1 125	133	956	OVER
16	-	-	133	1 352	209	1 361	133	1 352	UNDER
18	-	-	209	484	209	484	209	484	OVER
19	-	-	133	1 118	209	435	209	435	OVER
20	-	-	74	1 316	334	1 124	91	1 427	UNDER
21	-	-	64	1 033	324	445	90	1 133	UNDER
22	-	-	134	584	139	538	102	753	OVER
23	-	-	134	2 246	134	2 246	76	1 253	UNDER
24	-	-	51	902	51	902	51	902	OVER
25	-	-	48	633	133	831	82	645	UNDER
26	-	-	133	673	393	-163	133	669	LOW
27	-	-	0	0	138	730	133	886	OVER
28	-	-	138	831	138	831	133	797	UNDER
29	-	-	336	2 732	474	2 969	296	1 937	UNDER
30	-	-	260	-1 656	393	-2 869	260	-1 656	VERY LOW
Total		**0**		**19 944**		**15 824**		**18 758**	

opportunities is not optimal and the results for strategy 1 shows the consequences of pricing too much capacity too high and out of the market. With a price of 20 EUR/MW some part of the offered volume for the producer in question will often have a quite good buffer with regard to the price. E.g. for the situation in table 8.1 we see that 3 MW is offered for a minimum price of 8 EUR/MW. This is the price where this part of the capacity(3 MW) basically is indifferent between selling the capacity or not. For a minimum price of 13 EUR/MW the offered volume is 5 MW, but only 2 MW of this capacity is indifferent between selling or not. 3 MW of this capacity now receives a quite healthy profit in the LFC^+ market with the 13 EUR/MW price compared to the expected profit this part of the capacity has in the spot market. With a price of 20 EUR/MW there will in most weeks exist enough capacity with a good enough buffer to make strategy 1 quite bad compared to the other strategies.

That strategy 2 and 4 beats strategy 3 shows that the single-scenario model with the price forecasts from Statkraft indeed prices the bids too low. The offered volumes is for strategy 2 and 4 equal or lower than the offered volume for strategy 3 for all the weeks. Some variance is of course present here due to the sample size, especially because of the large size of some of the units. E.g in week 8 it can be seen that the sold volume is 469 MW for strategy 2, which is much larger than for the other strategies. This volume difference is mostly due to the utilization of unit SyS in strategy 2. The consequence of the spot price outcome, both good and bad, related to the forecast would then monetary wise be much larger than for weeks where the volume difference between the strategies were made up by smaller units or smaller parts of the capacity. One good(or bad) week when the volume differences is especially large could thus skew the results a bit, but the sample size seems large enough here to conclude that strategy 2 doesn't give the best bids.

Column *DIFF* shows as mentioned rough estimate of how the spot price outcome of the weeks was relative to the single-scenario price forecasts during the period. **LOW** means that the actual spot price was on average more than 2.5 EUR/MW under the forecast in each hour during the week. **UNDER** means less than 2.5 EUR/MW under the forecast. **HIGH** means that the actual spot price on average was more than 2.5 EUR/MW over the forecast, while **OVER** means less than 2.5 EUR/MW over the forecast. **VERY LOW** means on average more than 5 EUR/MW under the forecast in each hour during the week. By taking a look at week 1 and week 11 it can be seen how both sides of the forecast can give increased cost for up-regulation spinning reserves. In both these weeks the profit is higher for strategy 1 than for strategy 3. This could not be the case for other types of reserves. Only one of those weeks could then have shown a higher profit for strategy 1 than strategy 3 depending on the type. Week 1 could e.g for manual up-regulation reserves(RK^+) not show a higher profit with strategy 1 since lower spot prices than the forecast could only reduce the cost of supply for the offered capacity.

That strategy 2 beats strategy 4 here is probably mostly luck and variance. Strategy 4 would give the best results over time if the scenarios perfectly match the statistical properties of the prices. This is not necessarily the case here of course, but the scenarios should be good enough to beat an arbitrary addition to bid price as was the case for strategy 2. The guaranteed buffer of 5 EUR/MW for all the offered capacity was apparently a good(lucky) number to account for the spot price uncertainty in these weeks, but it does show that a single-scenario deterministic MIP can provide good bids if the bids are adjusted to account for price uncertainty. The single-scenario model finds suitable units and volume blocks to offer as reserves even though they are priced too low. It is actually strategy 3 that shows the highest profits for the highest number of weeks in table 8.1. This is mostly for the weeks where the difference between the forecast and the actual spot prices were small. So strategy 3 gives good bids in situations with low price uncertainty. The multiple scenarios in strategy 4 should of course be adjusted for situations with lower uncertainty and the natural conclusion is that the buffer for strategy 2 should be lower for situations with lower price uncertainty and higher for situations with higher price uncertainty.

Under 20 000 EUR extra profit compared to not selling any reserves may not sound like much when selling over 100 MW each week for 28 weeks, and it really isn't a lot of money in this respect. The low price of 20 EUR/MW is to blame for this, but we see that a lot of MW is offered for this price so the price doesn't need to be higher. Other periods of the week may have higher prices than the evening period used here, but that would be accompanied by higher costs for the units and the profits wouldn't necessarily be higher. The volume segments given in bids for markets with marginal pricing are supposed to be given for prices where the volume is indifferent between supplying or not, and when the demand in the market can be fulfilled by very few volume segments it does not leave much room for high profits in the market. So assuming correct and efficient bids from producers in Norway it is absolutely plausible that the capacity reserve markets for secondary control won't be very lucrative when demand is low compared to unit and station sizes.

Chapter 9

Further discussion

9.1 Not a pricetaker

9.1.1 Spinning requirement issue

The producer has in the bid optimizations been assumed to be a pure price taker on all markets. This means that his actions in the different markets can' effect market prices. This may be a reasonable assumption for the spot market, but the demand on the reserve markets are much lower compared to the capacity available in a power system. The demand for secondary control reserves is especially low compared to the size and supply capability of generating units and the notion of pure price takers on these markets seems farfetched. The total requirement for automatic secondary control(LFC) in Norway are also likely to be split into several price areas based on geographical locations and limitations making the demand in the price areas even smaller compared to unit and station sizes. The unit *SyS* or e.g. the unit *Gry* can probably supply this quantity for specific price areas alone, so it is likely that not even a single unit can be said to be a price taker on these markets.

Even so, there is competition on the markets and any market power for single producers is not supposed to be used anyway. Low demand compared to the possible supply actually ensures that there is healthy competition with no market power for single producers. So the bids given by the method is in principle still a good strategy since it offers the optimal volume for given prices and obligations. A problem with the method when not a pure price taker arises due to the characteristics of spinning reserves though.

In section 6.2.2 we saw that units with an obligation for primary control reserves must be spinning and available capacity for up-regulation secondary control can be supplied from this unit without accumulating the 'fixed' costs from hours where the spot price is too low. Assume that the power system is not capacity constrained in any direction meaning that the capacity price for tertiary control reserves and down-regulation reserves should be zero. This should be the case for normal load situations in a power system. Consider the unit *Gry* and consider for simplicity a period where the spot price is below this unit's production costs for all hours. The accumulated 'fixed' costs to keep the unit spinning during this period are 500 EUR. To illustrate the point we consider that the unit is bidding for FNR^{+} supply and ignore direct costs connected to primary control supply. We also assume that the demand for FNR^{+} is high compared to the supply capability of individual units and that the LFC^{+} demand can be fulfilled by few or even single units. With a droop setting of 2% the unit can supply 14 MW of FNR^{+}. To cover the 'fixed' cost with this supply alone the unit would require a compensation of

$500/14 \approx 36$ EUR/MW. The unit still has 109 MW available for spinning up-regulation capacity though. The same unit bidding for LFC^+ would offer 133 MW for a required compensation of $500/133 \approx 3.8$ EUR/MW. We assume that this volume would fulfill most of the demand and that the unit would have been the marginal unit in the LFC^+ market giving an expected price of 3.8 EUR/MW. So instead of requiring a compensation 36 EUR/MW for FNR^+, the unit could now offer 14 MW for 3.8 EUR/MW. This bid would almost certainly be accepted since with the unit being competitive for LFC^+ a lot of other units with higher opportunity costs would have to be used to fulfill the total FNR^+ demand. In addition to *Gry* consider the unit *Bjol*. This unit can supply 9 MW of FNR^+ with a droop setting of 2%. Let this unit have accumulated 'fixed' costs during the period of 500 EUR too. To cover the 'fixed' cost with FNR^+ supply alone the required compensation would be $500/9 \approx 56$ EUR/MW. The unit still has 67 MW available for spinning up-regulation capacity though. Bidding for LFC^+ the unit would have offered 76 MW for $500/76 \approx 6.6$ EUR/MW. This is above the expected price, but any income from the available capacity could contribute to cover the 'fixed' costs if supplying FNR^+. With an expected price of 3.8 EUR/MW for LFC^+ the required compensation for FNR^+ would be $(500 - 67 * 3.8)/9 \approx 27$ EUR/MW for the 9 MW. We assume that also this bid would be accepted and that it would be the final price for FNR^+. With the obligations from the FNR^+ market the subsequent bids for the two units would be the remaining available capacity for 0 EUR/MW since the 'fixed' cost now would be a sunk cost with the units obligated to be spinning during the period. This is perfectly fine for price takers since the costs are truly sunk with the FNR^+ market being history and any income at all from the LFC^+ market, even 1 EUR, will now contribute to increased profits. The problem comes when the units are not price takers. The volume from these units offered at 0 EUR/MW would completely destroy the price for LFC^+ since this volume alone would fulfill the demand and the bids from the units would be the marginal bids. The unit *Bjol* wouldn't even have supplied anything for the expected price of 3.8 EUR/MW without the obligation from the FNR^+ market and clearly lowers the price. So the units would now actually have lost respectively $500 - 14 * 27 = 122$ EUR and $500 - 9 * 27 = 257$ EUR in the markets since the bid in the LFC^+ market put the price at zero instead of the expected 3.8 EUR/MW.

Using the expected price for the subsequent LFC^+ bid is not really an alternative since the volume could then possibly not be accepted, and using an expected price of zero for LFC^+, which actually is the expected price with the FNR^+ obligations, would give too high bids for FNR^+. Not having the obligations from FNR^+ wouldn't give the cost free bids for LFC^+ that reduced the price to zero. Unit *Gry* would in this case still have been accepted with the bid of 3.8 EUR/MW though. So there could be no expected price and price forecast in this case since the price would be zero if the 'expected price' was forecasted and the 'expected price' if the forecast was zero. The price forecast in the model would ultimately have to be zero in this case though so that the units would give safe bids on all markets. For the power system as a whole it would mean that the demand isn't met in the most effective way that would maximize the social surplus. Normally, a price forecast that changed with the supply in the model could account for not being a price taker. E.g. very simplified, 0 MW of LFC^+ supply from the unit *Gry* would give a price of 3 EUR/MW, 50 MW - 2 EUR/MW, 80 MW - 1 EUR/MW and 109 MW - 0 EUR/MW. This does not give the desired effect here since the 'fixed' cost is not coupled to the supply. The optimization would just choose the amount that gave the highest profits, $50 * 2 = 100$ EUR, so that the required compensation for the 14 MW for the FNR^+ market would be $(500 - 50 * 2)/14 \approx 29$ EUR/MW. If this was accepted, the bid for LFC^+ would still be 109 MW for 0 EUR/MW.

This is an extreme example of course, and with more than one unit in the set of generating units in the bid optimization it becomes a bit more complex since the FNR obligation of e.g. 14 MW could possibly be fulfilled by other unit combinations for a lower cost than unit *Gry* could without getting the expected income from LFC^+. The point is that any price forecast other than zero from the future LFC^+ market leads to bids from the units on the two markets that combined will not cover the accumulated 'fixed' costs by itself. The bid in the first market will be based on the forecast and the bid in the future market will always be lower than the forecast if the bid in the first market is accepted, which is problematic when the bid sets the price in the future market. To not have this problem the markets would basically have to be organized differently than the markets assumed here, for example with bids for both markets given together. Unit *Gry* could e.g. offer 14 MW for FNR^+ and 109 MW for LFC^+ under the condition that the average price per MW sold was above 3.8 EUR/MW. This would not be sequential market auctions and is different from the assumptions in the model, so we will not discuss such subjects further here.

There is no real solution in the model for the problem since the bid strategy is theoretically sound for the units. The accumulated 'fixed' costs should not be considered if it is already known that the unit is spinning. The issue here is that units with spinning obligations from the first market are setting the price in the second market . A practical solution in this case is to change the market order of primary and secondary up-regulation capacity reserves so that the market for secondary control clears first, even though the same mechanism exist the other way too. The important factor is the assumptions that few units may cover the LFC^+ demand, while several units are required to cover the FNR^+ demand. We use the price of 27 EUR/MW from before as the expected price for FNR^+. Unit *Gry* would now require $(500 - 14 * 27)/109 \approx 1.1$ EUR/MW for LFC^+, while unit *Bjol* would require $(500 - 9 * 27)/67 \approx 3.8$ EUR/MW. Unit *Gry* offers thus 109 MW for 1.1 EUR/MW and we assume that this fulfills the demand with unit *Bjol* being rejected in the market. So *Gry* would be the only unit with sunk costs in the FNR market, the FNR^+ price should not be affected much and *Bjol* is not duped by false hopes from the future market.

9.1.2 Marginal effect in the spot market

The model uses fixed spot price forecasts and assumes thus that actions in the capacity markets won't affect the spot price when calculating bids. This is true for manual reserves since the reserve requirements always are fulfilled in the same way with regard to the consequences for the spot market. For spinning reserves this isn't necessarily true.

The requirement for up-regulation spinning reserves will as we have seen be fulfilled by either units that are profitable in the spot market and are likely decreasing spot production to make room for the reserves, or by units that aren't profitable in the spot market, but are increasing spot production to at least the minimum production level to fulfill the spinning requirement. These two types are competing on equal terms in the model and the competitive bids from the producer would be made up by volume from the units that can supply the reserves for the required low cost with the given fixed spot price forecast. The price in the spot market is set by the matching of supply and demand and is of course affected by changes to the supply curve. Putting uncompetitive spot supply at the bottom of the supply curve would normally lower the price and taking competitive spot supply out of the curve would normally raise the price compared to the same situation with the default supply curve. So fulfilling the up-regulation spinning reserve demand with units that wouldn't otherwise have produced anything for the spot market would probably lower the resulting spot price compared to fulfilling the demand with units that otherwise would have produced more for the spot market. The producer supplying these reserves would also normally have much more spot production from other units which gets a lower profit when the spot price is lowered. The price forecast in the model may be the correct forecast, or not, but it doesn't matter since the actual spot price outcome would change depending on the type of unit supplying the spinning reserves.

This effect cannot be accounted for in the model, but it is clear that supplying up-regulation spinning reserves from units that otherwise wouldn't have any spot production potentially could give huge cost if the spot price is altered. For a supply of 80 MW of up-regulation spinning reserves and units with minimum production levels of 20 MW it could mean a difference of 100 MW in the supply curve below the spot price. This shouldn't be significant but if it has a marginal effect on the spot price, it could be that accumulated costs in the model for units in hours with expected spot price below the productions costs are way too low, and bids from the producer utilizing these units would thus be too low. With the same logic it goes the other way too of course. Accumulated costs for units that otherwise should produce would be too high giving too high bids from these units. So the effect shifts the cost balance between units with higher and lower production costs, which, if it exists, aren't accounted for in the model.

9.2 Max/min bid volumes

9.2.1 Minimum bid sizes

The model presented so far does not restrict bids on any of the markets to any specific bid size, and capacity bids from the model may in theory have any size from zero to the maximum available capacity. System operators will in reality often put size restrictions on bids though. Minimum bid sizes in the capacity markets is not a problem since bids can just be chosen to be above this size, but minimum bid sizes in energy reserve markets needs to be represented in the model also for the capacity supply. For primary control reserves there is no point in minimum bid sizes since the reserves are activated automatically and locally, but the system operator in Norway, Statnett, operates with minimum bid sizes in the energy markets for tertiary control reserves. These bids are activated manually over telephone and Statnett requires station specific bids of minimum 25 MW for most participants with a option of 10 MW for small participants[5] in the energy market. For the capacity reserve market that ensures that enough capacity is made available for the energy reserve market it means that the bid must be made up of stations that contributes at least 25 MW each. A producer using the model and offering 50 MW in the capacity market where the model calculated that 40 MW would come from station 1 and 10 MW from station 2 in the capacity constrained situations during the obligation period would possibly price this volume incorrectly since station 2 would have to bid 25 MW and not 10 MW in the relevant hours during the period. To model minimum bid sizes in the model would require additional binary variables in much the same way that the binary variables are included for minimum spot production. The meaning of station specific minimum bid sizes for capacity reserves in the model is, when we assume that each station consists of only one unit, exactly the same as the meaning of units' minimum production levels. A unit can supply either zero reserves or more than the minimum requirement, just as a unit can produce either zero or more than the minimum production level(requirement).

9.2.2 Maximum bid sizes

Maximum bid sizes is not a point for energy reserve markets, but it might be a point for capacity reserve markets. For manual reserves where the reserve requirement in an area is reasonable large compared to station(unit) sizes it shouldn't be necessary, but especially for secondary control it might have some use. As shown earlier in this report a unit will due to the 'fixed' cost often want to supply the maximum capacity for a given price. With the reserve requirement for up-regulation secondary control in an area being quite small compared to station sizes, at least in Norway, the risk is that the requirement will be fulfilled by only one unit and that the volume offered from this unit even exceeds the reserve demand. That secondary control is only provided by one unit might increase the risk for the system operator, especially if the energy reserve market for secondary control in each hour during the obligation period isn't open to bids from unit/producers that haven't been accepted in the capacity market.

The issue that volume is offered in large discrete blocks so that supply can't be matched with the demand is a more interesting issue. Assume that the system operator wants to buy 100 MW of LFC^+ capacity in an area. The bids available in the market is the same as the bids in table 7.4. There is a huge jump between 26 MW and 149 MW and with the bids having to be accepted in full or not at all, the system operator would have to buy 149 MW to fulfill his demand of 100 MW. That the supply of capacity reserves doesn't match demand is of course not a problem like it is if spot supply and demand doesn't match. Increased supply of reserves can only improve the power system security, but buying 149 MW for 15 EUR/MW instead of 100 MW increases the total cost for the system operator. Requiring that producers supplies bids in maximum volume step sizes would ensure that a volume closer to 100 MW could be bought. The problem is the possible falling supply curves of individual units supplying secondary control. Take as an example unit Gry with a minimum production($Ymin$) of 10 MW and maximum($Ymax$) at 143 MW. During an obligation period assume that this unit can't make a profit in the spot market and accumulates 'fixed' costs at minimum production over the period of 1000 EUR. A producer providing bids from this unit in maximum steps of 25 MW would then require $1000/25 = 40$ EUR/MW for 25 MW, $1000/50 = 20$ EUR/MW for the next 25 MW and finally $1000/133 \approx 7.5$ EUR/MW for the final step. So we see that the bid curve from the producer wouldn't necessarily be strictly increasing. This is not theoretically sound when creating market equilibriums using marginal pricing as any bids below the clearing price should be accepted. So any maximum bid sizes for secondary control would with a free market solution ideally have to be station specific with one maximum size for each station.

Still, the system operator is at liberty to create the market rules he deems to be the best. Including any type of maximum bid size is not a problem for the method though. Constraints are just added in the model for bids with maximum sizes, and removed for bids without. The constraints would just be upper constraints and no binary variables are needed. A market solution for secondary control where units had to provide at least one maximum size bid, but at the same time could provide bids of optional size would mean that it would be important for the secondary control capacity markets to clear first. Price forecasts where it is impossible to know how much volume a unit actually would sell creates problems when pricing bids for previous markets.

9.3 Energy reserve markets

In the model we have not included any effects of the energy reserve markets. This is a simplification. Profits from activation of reserves are just as valuable as profits from any other markets, and opportunities in these markets should be accounted for when valuing capacity for other markets. The connection between the spot market and the reserves markets(capacity and energy) are for manual reserves more thoroughly investigated in [3], but to put it shortly the total market equilibriums also includes the income and costs from the energy reserve markets.

If the expected value in the energy reserve markets for enough capacity is higher than the value in the spot market, there should be no need for capacity reserve markets. Expected profit for a unit in an energy reserve market should then contribute to lower this unit's required compensation in the connected capacity market, but it is not really quite so easy since this unit must consider energy markets for other reserve types also, just as the capacity markets for other reserve types must be accounted for.

Consider now up- and down-regulation tertiary control reserves for a single hour and ignore other control types. The energy markets for these reserves are real-time markets with marginal pricing and we assume for this hour that the need for regulation is symmetric for up- and down-regulation. This is natural, but we also assume here that the resulting prices from the regulation are symmetric for up- and down-regulation. There is a capacity price for up-regulation manual reserves in this hour and the marginal price-setting capacity for these reserves is thus indifferent between producing for the spot market or not. This unit would in this hour be the first activated unit for up-regulation and would definitely have an expected profit from the up-regulation energy reserve market, but the unit would also have been the first activated unit for down-regulation had he produced for the spot market instead. So the unit has the same expected profit from the down-regulation energy market and the unit's expected profits from the up-regulation market would thus not influence his required compensation in the capacity market for up-regulation reserves. The markets for up-regulation and down-regulation regulation are not likely to be completely symmetric very often though, and the expected regulation profits will for the marginal capacity in situations with a capacity price for up-regulation reserves probably be higher for up-regulation lowering the required capacity compensation for the marginal unit. But the down-regulation energy market and other energy reserve markets are still part of the equation for units bidding for the capacity reserves.

Including all real-time markets correctly in the model to include expected profits for all units on all markets is a huge challenge though. The demand in the real-time energy reserve markets is stochastic in each hour during a period and the price will with marginal pricing depend on the demand. So the price in each hour can only be described with a probability distribution for several outcomes. And even though the price for a certain regulation type is fixed it doesn't help the fact that the demand is uncertain. The payment in the real-time energy reserve markets is for activated energy and the quantity of activated energy is stochastic in each hour. So a unit's income from real-time energy reserve markets in an hour will be highly uncertain even if prices are fixed and known. Challenges of including these type of markets in an optimization model is to some degree covered in [3], but it seems clear that including such markets accurately in a MIP-model used for bidding can give unacceptable calculation times compared to the significance of these markets on the capacity bids.

These markets have as mentioned been completely ignored in the optimizations in this report and the reasoning is that the potential profits from these markets have been assumed to be negligible. The need for regulation is in Norway most of the time quite small in each price area compared to the units normally available for regulation. With the units bidding their marginal costs and e.g only one unit being activated in each hour it leaves little room for profit. The probability for price spikes in the regulating markets has also most of the time been quite low. The importance of these markets might increase though and should be accounted for in capacity bids and thus also accounted for in some way in the model.

A primitive simplification in the model could be to just adjust the bids by adding an income or cost per MW[1] supplied in each market representing the expected profit in the connected energy

[1] Primary control activation are not compensated for, but activation for down- and up-regulation are mostly expected to even out for a unit. Even so there could be a cost connected to primary control activation

market for the marginal capacity in the different capacity markets. All capacity offered for a reserve market in the model is offered for a price where this capacity in principle is indifferent towards supplying for some other reserve market. So the bids would be adjusted by the difference of the added income or cost for the two reserve markets. This simplification has a number of different weaknesses for all the different markets that we will not study further in this report, but we will consider a case for secondary control where both this primitive simplification and neglecting the secondary control energy markets will give very wrong results from the model.

So far we have assumed open energy markets for secondary control with marginal pricing where any available capacity can be offered for the energy market in every hour during the period. This is a natural assumption when we have assumed that the producers offering capacity in the capacity market can choose how this obligation is met by changing the supplying units during the obligation period. In this case the energy markets for secondary control could be neglected for the capacity bids in the same way as for the other reserve types without causing too much trouble for the bids. In practice it might be hard for the system operator to have open energy markets for secondary control in each hour under an obligation period, and it can be understandable if secondary control energy markets are restricted to capacity procured in the capacity markets and even that the capacity bids are station specific. This gives isolated energy markets for secondary control and this is where bids for secondary control in the weekly market that consists of both a capacity price and an energy price comes into play. For up-regulation secondary control it wouldn't be so important since the spinning requirement and capacity considerations alone makes sure that the best units overall are used for regulation in each hour, and the capacity price should be sufficient as a selection criteria like it is for manual reserves. For down-regulation it is a bit different. When the power system is not capacity constrained on the down side there will be more than enough capacity available for down-regulation reserves without a capacity price. So competitive capacity bids for secondary control could and would come from units with marginal production costs way below the spot price. The best units to use for secondary control down-regulation should be the units offering capacity that has the highest marginal production costs and the offered energy price should thus be part of the selection criteria. This is does not create problems for the model or the method since one just checks the production costs of the units behind the bids. With marginal pricing in the energy markets it could still be ok to neglect the effects on the capacity bid if the expected profits are low.

The problem arises when a fixed price is used for secondary control activation, and especially so for station specific capacity bids. This fixed price would typically be connected to the spot price with the spot price plus some fixed amount for up-regulation and the spot price minus some fixed amount for down-regulation. For isolated energy markets it means that the bids in the capacity markets for secondary control doesn't need to consist of both a capacity price and an energy price. The fixed price should secure the best units in the capacity market with just the capacity price as selection criteria. For the model it means that bids can be badly calculated. If we consider the case with station specific bids we see that different units will have production costs with different distances to the fixed activation price for each hour. This distance can be large and the expected profit or loss from this distance must be accounted in the bids from the units. If we look at LFC^- in a situation where the power system is not capacity constrained on the down side, the producer in the model may have many units with production costs far below the spot price in all hours during a period. Without energy markets in the model all these units would offer LFC^- control capacity for the same low price. With a fixed price in the secondary control energy market connected to the spot price many of these units would take a loss if and when down-regulated. This loss should have been reflected in the bids in the capacity market. Units with lower marginal production costs should get a higher cost of supply so that the bids from the producer are priced correctly. This does not happen in the model without the energy market correctly included. This market solution for secondary control energy markets is the most probable solution Statnett will use in the implementation of secondary control[source], so it is crucial for producers that these markets are accounted even though other energy reserve markets can be neglected due to very low profit. An isolated energy market with fixed prices connected to the spot price would be the least problematic market to model though, but we will not go further with this here.

A curiosity with isolated energy markets for secondary control where activated capacity must have been accepted in an earlier capacity market is the possibility for negative bids or prices. If expected profits for a unit in an energy market for secondary control were higher than the expected profits for any other possible use of the capacity, the unit would in theory be willing to pay for the ability to supply the reserves and thus give a negative bid in the capacity market for the control type.

9.4 Changing water values

The model here uses constant water values for the units during the obligation period to calculate the bids. Together with the other simplifications in the unit descriptions it basically means that the units in the model aren't specifically hydro units. They are just production units described with a resource cost and efficiency curves. For hydro units the resource cost, i.e the water value, can change depending on reservoir levels and thus the water use during a period.

The whole basis behind the need for capacity prices for reserves is the altering of the optimal production commitments during a period. For hydro units this means that supplying reserves can change the expected water use during the period and thus change the water values. For up-regulation manual reserves the need for a capacity price for a unit means that the water use during the period will be lower than expected. This means that the reservoir level for the connected reservoir at the end of the period will be higher than expected and the water value has changed during the period to be lower. A lower water value and resource cost for the unit during the obligation period means that the required capacity price for the unit would increase compared to a constant water value. For down-regulation reserves it would be the other way around with the need for a capacity price for a unit giving more production than expected and a higher water value, increasing the required capacity price for the unit.

For up-regulation spinning reserves the supply can both increase the units expected production during the period and decrease it. In hours where the unit is not supposed to produce the spinning requirement increases the expected production and in hours where the unit is supposed to produce the reserves decreases the expected production. For a unit that is not supposed to produce at all during the period the water value will increase and the required compensation will increase too compared to a constant water value. For a unit that is supposed to produce in the whole period, the water value will decrease and the required compensation will increase also for this unit. For a unit that is in both situations during the period it will depend on which mechanism that is the dominating factor.

So it is better if the water values aren't constant in the model when using a MIP-model to calculate bids.

9.5 Calculation times

Part of the appeal of a single-scenario deterministic model used as decision support for bidding in the markets talked about in this report is fast calculation times. MIP-models or short-term hydro optimization models that realistically would be used for the purpose of bidding with the method shown here would be infinitely more complex than the model in this report and high calculation times is a real concern that would limit the methods value for operational use. The single-scenario model used here does not require much computational effort at all and the calculation times are very fast and even though only 20 hours have been used for optimizations in this report, it is no problem to calculate bids for far longer obligation periods. The inclusion of reserve markets should in single-scenario deterministic models not increase the calculation time significantly compared to just describing the spot market.

The multi-scenario model requires a lot of computational effort which was the reason to cut down the segments on the PQ-curve from 4 to 2 segments, and the reason to use a relative short obligation period of 20 hours for illustrations of the model. The computer used for the optimizations ran out of memory quite fast and the calculations time used for the multi-scenario model runs had to be limited and was limited to 9 minutes. So the solutions of the multi-scenario model runs in this report can't actually be guaranteed to be the optimal solution, but they are close and the objective function value are at least within 0.1% of the objective function value for the optimal solution. Not all optimizations required the maximum time, but the bid levels close to volume jumps required a lot of branch and bound nodes. Price levels where the optimal commitment is clearer were a lot faster. E.g just running the spot market without any reserve prices was quite fast.

9.6 Further work

The markets assumed for the illustrations of the model and method and the benchmarking in this report were for general and ideal markets with no specific restrictions. Modeling specific market solutions and looking at realistic situations where realistic price forecasts for all markets are given could give more interesting analysis.

It is natural to expand the model to better represent hydro-units and reservoir systems. All units presented here are 100% flexible and all supply is just a matter of individual unit capacity. The logical final step is of course to include reserve capacity markets in existing short-term hydro-optimization models that are used on a daily basis by power producers and use this for analysis.

How to include energy reserve markets in the model and in general how different energy reserve markets should be accounted for in different capacity reserve markets is absolutely something that can be expanded on. The real need for a method that accounts for opportunity costs from all capacity markets comes with significant prices and volumes in these markets. With a need for significant volumes in capacity markets one could probably also assume that the need for regulation in energy reserve markets would be significant. With hydro-units being well suited for reserve supply it could also be interesting to investigate how and if significant reserve prices will impact water values in the long term.

With regard to price uncertainty in future markets it could be interesting to look at how this uncertainty should be accounted if a deterministic model that doesn't include price uncertainty is used to calculate bids.

Chapter 10

Conclusion

In this report we have shown how a MIP-model can be used for bidding in sequential capacity reserve markets. The method takes into account costs and opportunity costs for all markets included in the model and find the optimal allocation of capacity on the different markets. This way bids can be calculated that represents the actual cost of supply for a market.

The reason why mixed-integer programming is suitable in this respect is the spinning requirement for fast automatic reserves and the minimum production levels of production units. Start-up costs for units are also something that can influence the cost of supplying capacity reserves.

The method is really only limited by what it is possible to model and describe in a MIP-model. With a perfect description of reality in the model the method produces optimal bids. A perfect description of reality is not easy or even possible, but as long as one is aware of weaknesses in the modeling and method it is nothing that says the results can't have value.

It has been shown in this report how important price uncertainty and volatility in future markets is for the valuation of capacity. The bid optimizations proved that capacity bids that don't consider price uncertainty are priced too low. The bid optimizations considered only price uncertainty in the spot market, but price uncertainty for future capacity reserve markets is also important for the valuation of capacity in previous markets. Considering price uncertainty of future competing markets is crucial for capacity reserve supply regardless of how the capacity bids are calculated.

Modeling of capacity reserve markets is not overly complex and in its purest form basically reduces to the constraints 4.20-4.22 in the model. A unit's capacity must be split between the different markets which should be decided by the most profitable allocation. So the inclusion of capacity reserve markets in MIP-models that describes the spot market should not increase the complexity of the models dramatically. The two different types of primary control for the assumed units here could not really successfully be correctly modeled in this report, but it should be possible to model a great variety of market solutions for capacity reserve markets in a MIP-model. Handling station specific bids, location specific bids, max/min bid sizes and similar restrictions is not a problem. A bidding method must in general adjust to the reigning market solutions, but it can also be an idea that market solutions adjusts to suit bidding methods that can provide efficient bids.

Modeling of energy reserve markets is more complex and no effort has been done to do so in this report. These markets can however play an important role for the market equilibriums and for specific bids, and it is something that must be considered in capacity reserve bids. The importance of these markets will likely increase in the future and the opportunity costs they create should be considered.

The method has been presented under the assumptions of perfect markets where good price forecasts can be given on all markets and market participants are pure price-takers. This is not always the case especially for capacity reserve markets. The minimum production level for units cannot be sold as spinning reserves and costs to keep a unit spinning during a period is thus not coupled to the amount of spinning reserves that can be sold. This can possibly give falling supply curves for individual units and the implications of this are important to consider in markets that are not perfect markets.

The biggest strength of the method is the ability to consider opportunity costs of all markets simultaneously and the ability to identify suitable units and bid volumes that will give the best unit commitment for spinning reserve supply in every hour during an obligation period. The last part is important for primary and secondary control when units contributing to the reserve supply are allowed to change from hour to hour.

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Appendix A

Referred tables

Table A.1: Specified unit commitment for the up-regulation part (FDR^{+}) of the 50 EUR/MW bid(96 MW) in table 6.3

Hour	Adam (MW)	Aura (MW)	Bjol (MW)	Gry (MW)	Leir (MW)	Mar (MW)	SyS (MW)
1	-	-	23.04	57.2	16.1	-	-
2	-	-	23.04	57.2	16.1	-	-
3	-	-	23.04	57.2	16.1	-	-
4	-	-	23.04	57.2	16.1	-	-
5	-	-	23.04	57.2	16.1	-	-
6	-	-	23.04	57.2	16.1	-	-
7	-	-	23.04	57.2	16.1	-	-
8	-	-	23.04	57.2	16.1	-	-
9	-	-	23.04	57.2	16.1	-	-
10	-	-	23.04	57.2	16.1	-	-
11	-	-	23.04	57.2	16.1	-	-
12	-	-	23.04	57.2	16.1	-	-
13	-	-	23.04	57.2	16.1	-	-
14	-	-	23.04	57.2	16.1	-	-
15	-	-	23.04	57.2	16.1	-	-
16	-	-	23.04	57.2	16.1	-	-
17	-	-	23.04	57.2	16.1	-	-
18	-	-	23.04	57.2	16.1	-	-
19	-	-	23.04	57.2	16.1	-	-
20	-	-	23.04	57.2	16.1	-	-

Table A.2: Specified unit commitment for the down-regulation part (FDR^{-}) of the 50 EUR/MW bid(96 MW) in table 6.3

Hour	**Adam (MW)**	**Aura (MW)**	**Bjol (MW)**	**Gry (MW)**	**Leir (MW)**	**Mar (MW)**	**SyS (MW)**
1	-	6.1069	35.6	-	40.2331	14.4	-
2	-	6.1069	35.6	-	40.2331	14.4	-
3	-	6.1069	35.6	-	40.2331	14.4	-
4	-	6.1069	35.6	-	40.2331	14.4	-
5	-	6.1069	35.6	-	40.2331	14.4	-
6	-	6.1069	35.6	-	40.2331	14.4	-
7	-	6.1069	35.6	-	40.2331	14.4	-
8	-	6.1069	35.6	-	40.2331	14.4	-
9	-	6.1069	35.6	-	40.2331	14.4	-
10	-	6.1069	35.6	-	40.2331	14.4	-
11	-	6.1069	35.6	-	40.2331	14.4	-
12	-	6.1069	35.6	-	40.2331	14.4	-
13	-	6.1069	35.6	-	40.2331	14.4	-
14	-	6.1069	35.6	-	40.2331	14.4	-
15	-	6.1069	35.6	-	40.2331	14.4	-
16	-	6.1069	35.6	-	40.2331	14.4	-
17	-	6.1069	35.6	-	40.2331	14.4	-
18	-	6.1069	35.6	-	40.2331	14.4	-
19	-	6.1069	35.6	-	40.2331	14.4	-
20	-	6.1069	35.6	-	40.2331	14.4	-

Table A.3: Specified unit commitment for the up-regulation part (FDR^{+}) of the 50 EUR/MW bid in table 6.4

Hour	**Adam (MW)**	**Aura (MW)**	**Bjol (MW)**	**Gry (MW)**	**Leir (MW)**	**Mar (MW)**	**SyS (MW)**
1	3	-	29	57	16	-	-
2	-	-	36	57	13	-	-
3	-	-	36	57	13	-	-
4	-	-	36	57	13	-	-
5	3	-	-	-	-	-	103
6	3	-	29	57	16	-	-
7	-	-	36	57	13	-	-
8	-	-	36	57	13	-	-
9	-	-	-	-	-	-	105
10	3	-	-	-	-	-	103
11	3	-	29	57	16	-	-
12	-	-	36	57	13	-	-
13	-	-	-	-	-	-	105
14	3	-	-	-	-	-	103
15	3	-	29	57	16	-	-
16	-	-	36	57	13	-	-
17	3	-	29	57	16	-	-
18	3	-	29	57	16	-	-
19	3	-	29	57	16	-	-
20	-	-	36	57	13	-	-

Table A.4: Specified unit commitment for the down-regulation part (FDR^{-}) of the 50 EUR/MW bid(105 MW) in table 6.4

Hour	**Adam (MW)**	**Aura (MW)**	**Bjol (MW)**	**Gry (MW)**	**Leir (MW)**	**Mar (MW)**	**SyS (MW)**
1	4	12	36	-	40	14	-
2	-	12	36	-	44	14	-
3	-	12	36	-	44	14	-
4	-	12	36	-	44	14	-
5	3	7	36	-	46	14	-
6	4	12	36	-	40	14	-
7	-	12	36	-	44	14	-
8	-	12	36	-	44	14	-
9	2	2	0	-	8	0	94
10	3	7	36	-	46	14	-
11	4	12	36	-	40	14	-
12	-	12	36	-	44	14	-
13	-	0	6	-	0	0	105
14	3	7	36	-	46	14	-
15	4	12	36	-	40	14	-
16	-	12	36	-	44	14	-
17	4	12	36	-	40	14	-
18	4	12	36	-	40	14	-
19	4	12	36	-	40	14	-
20	-	12	36	-	44	14	-

Table A.5: Benchmarking including objective function value

Week	**Str1**			**Str2 SING+5**			**Str3 SING**			**Str4 MULT**			**Diff**
	BID (MW)	**OBJ (EUR)**	**COMP (EUR)**	**BID (MW)**	**OBJ (EUR)**	**COMP (EUR)**	**BID (MW)**	**OBJ (EUR)**	**COMP (EUR)**	**BID (MW)**	**OBJ (EUR)**	**COMP (EUR)**	
2	-	2963	-	0	2963	0	132	1770	-1194	132	1770	-1194	LOW
3	-	405	-	5	233	-172	138	-203	-608	136	-92	-497	LOW
4	-	1170	-	8	1203	33	141	1629	459	133	1593	424	UNDER
5	-	604	-	0	604	0	133	991	387	133	991	387	UNDER
6	-	3578	-	0	3578	0	133	4442	864	133	4442	864	HIGH
7	-	6466	-	133	7338	872	469	8570	2104	133	7338	872	OVER
8	-	8424	-	133	9911	1487	469	11051	2627	146	9957	1534	OVER
9	-	2633	-	136	3422	789	396	3563	929	146	3398	764	UNDER
10	-	1791	-	136	2826	1034	396	3074	1283	141	2833	1042	UNDER
11	-	33867	-	127	34038	171	311	28617	-5250	209	32570	-1297	HIGH
12	-	3295	-	157	4174	879	157	4174	879	133	4465	1170	LOW
13	-	11456	-	153	13745	2289	159	13736	2280	133	13485	2029	UNDER
14	-	2888	-	138	3201	313	214	2963	75	133	3575	687	LOW
15	-	830	-	0	830	0	209	1954	1125	133	1786	956	OVER
16	-	3680	-	133	5032	1352	209	5041	1361	133	5032	1352	UNDER
18	-	8678	-	209	9162	484	209	9162	484	209	9162	484	OVER
19	-	9152	-	133	10271	1118	209	9588	435	209	9588	435	OVER
20	-	5731	-	74	7047	1316	334	6856	1124	91	7159	1427	UNDER
21	-	10914	-	64	11947	1033	324	11359	445	90	12047	1133	UNDER
22	-	38327	-	134	38911	584	139	38865	538	102	39080	753	OVER
23	-	18855	-	134	21101	2246	134	21101	2246	76	20108	1253	UNDER
24	-	47585	-	51	48487	902	51	48487	902	51	48487	902	OVER
25	-	25600	-	48	26233	633	133	26431	831	82	26245	645	UNDER
26	-	9080	-	133	9753	673	393	8917	-163	133	9749	669	LOW
27	-	138789	-	0	138789	0	138	139519	730	133	139675	886	OVER
28	-	69463	-	138	70294	831	138	70294	831	133	70261	797	UNDER
29	-	44897	-	336	47629	2732	474	47866	2969	296	46834	1937	UNDER
30	-	59874	-	260	58219	-1656	393	57005	-2869	260	58219	-1656	VERY LOW
Total		570996	0		590940	19944		586820	15824		589754	18758	