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# Standardprodukter for balansekraft

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**Abstract**

In the process of creating an internal European market for electricity, balancing power markets will be integrated to enable more efficient use of balancing resources. Due to regional differences between balancing markets and operations, ENTSO-E are establishing Network Codes to harmonize regulations for cross-border and market integration issues. This includes defining a set of Standard Products to be used for exchange of balancing services, as well as developing an "Activation Optimization Function". Optimal use of resources will depend not only on market integration, but also on the design of the Standard Products. A major purpose of this thesis is to investigate the use and behaviour of Standard Products. For a set of proposed Standard Product definitions, different characteristics and their influence on activation costs and behaviour will be investigated.

For this purpose, an optimization model for activation of balancing energy was developed, as well as a fictive set of bids representing the Nordic Regulating Power Market. Using these bids and the Standard Product definitions, the optimization model finds an optimal activation schedule to cover the imbalance forecast. Scenarios representing different activation requirements and imbalance situations were created.

Optimization results suggest that constraints imposed by inflexible product characteristics increase balancing costs, while more flexible arrangements allow merit order utilization of bids in the optimal solutions. Allowing adjustments of bid power levels during the delivery period is found to enable efficient use of resources.

The results found in optimization are optimal subject to the assumptions and simplifications made in the model. Among the most influential simplifications are the disregard of ramping energy, omitting a network structure, the simplified aFRR implementation, and ignoring uncertainty. Solutions have also been found sensitive to the penalty cost parameters, biases in input data and a modelling error preventing partial activation.

To obtain efficient use of balancing resources, balancing markets must not only be integrated and harmonized, effort should also be made in the design of Standard Products to avoid characteristics causing inflexibility unless strictly necessary.

**Sammendrag**

Som en del av prosessen med å etablere et felles marked for elektrisitet internt i Europa, skal balansemarkeder integreres for å legge til rette for effektiv bruk av balanseressurser. Som en følge av betydelige regionale variasjoner i driftspraksis og markedsregler, er ENTSO-E i ferd med å innføre Network Codes, et felles regelsett for systemoperatører. Disse setter retningslinjer for balansesamarbeid over grenser og integrering av balansemarkeder. For utveksling av balansetjenester skal det utarbeides Standardprodukter, samt en funksjon for optimal aktivering, kalt "Activation Optimization Function". Optimal bruk av ressurser avhenger ikke bare av integrerte markeder, men også av Standardproduktenes utforming. Et viktig formål med denne avhandlingen er å undersøke Standardproduktenes bruksmønstre og karakteristikker. Et foreslått utvalg Standardprodukter vil undersøkes for å avdekke ulike egenskapers innflytelse på balansekostnader og aktiveringsmønstre.

I denne hensikt har en optimeringsmodell for balanseenergi blitt utviklet. Sammen med et utvalg fiktive bud gjenspeiler dette en aktiveringssituasjon og regulerkraftmarkedet i det nordiske systemet. Disse budene brukes sammen med definisjonene for Standardproduktene til å finne en optimal aktiveringsplan som dekker en ubalanseprognose. Scenarier som gjenspeiler ulike krav i aktiveringen og ulike ubalansesituasjoner har blitt utformet.

Resultater fra optimeringen antyder at restriksjoner som følge av ufleksible produktegenskaper øker balansekostnadene, mens mer fleksible egenskaper muliggjør større grad av prisrekkefølge i aktiveringen. Effektiv bruk av ressurser ble oppnådd særlig når justering av produksjonsbidraget fra individuelle bud tillates i løpet av leveringsperioden.

Resultatene funnet av optimeringsmodellen er optimale under påvirkning av en rekke antakelser og forenklinger. Noen av de viktigste forenklingene er utelatelsen av energileveranse fra ramping, utelatelsen av nettverksstruktur, en forenklet aFRR-implementasjon og ignoreringen av usikkerhet. I tillegg er resultatene påvirket av straffekostnader, skjevhet i inndata og en modelleringsfeil som forhindrer delvis aktivering.

Integrering og harmonisering av balansemarkeder er alene ikke tilstrekkelig for å oppnå effektiv bruk av ressurser. Standardprodukter bør utformes slik at ufleksible egenskaper unngås dersom dette er mulig.

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# List of Abbreviations

**AC** Alternating Current

**ACE** Area Control Error

**aFRR** Automatically activated Frequency Restoration Reserves

**AGC** Automatic Generation Control

**ARIMA** Auto-Regressive Integrated Moving Average

**ATC** Available Transfer Capacity

**BMU** Balancing Mechanism Unit

**BOA** Bid Offer Acceptance

**BRP** Balance Responsible Party

**BSP** Balancing Service Provider

**CEGB** Central Electricity Generating Board

**CMOL** Common Merit Order List

**CoBA** Coordinated Balancing Area

**CWE** Central Western Europe

**EBS** Electricity Balancing System

**ENTSO-E** European Network of Transmission System Operators for Electricity

**EVPI** Expected Value of Perfect Information

**FCR** Frequency Containment Reserves

**FCR-D** Frequency Controlled Disturbance Reserves

**FCR-N** Frequency Controlled Normal Operating Reserves

**FRR** Frequency Restoration Reserves

**GCT** Gate Closure Time

**HVDC** High Voltage Direct Current

**ISO** Independent System Operator

**LFC** Load and Frequency Control

**mFRR** Manually activated Frequency Restoration Reserves

**NG** National Grid

**ROM** the Regulating Power Options Market

**RPM** the Regulating Power Market

**RR** Replacement Reserves

**STOR** Short Term Operating Reserve

**TSO** Transmission System Operator

**UK** United Kingdom

**VSS** Value of the Stochastic Solution

# Chapter 1

# Introduction

## 1.1 Introduction

As a part of establishing an internal market for electricity in Europe, the European Network of Transmission System Operators for Electricity (ENTSO-E) are currently developing a set of Network Codes, defining rules and regulations for European power markets. The Network Codes also include operational principles for transmission interconnections to be shared by all European Transmission System Operators (TSOs). One of the areas addressed by the codes is system balancing, i.e. the tasks related to ensuring the continuous balance between demand and supply, which is addressed in the Network Code on Electricity Balancing [1].

Among the main objectives of the Network Code are enhancing pan-European social welfare and ensuring operational security [1, Art. 10]. Specifically, the Network Code on Electricity Balancing aims to facilitate exchange of balancing services in order to achieve a more efficient use of balancing resources. Exchange of balancing services will require cooperation between TSOs and closer integration of European balancing markets. This process of harmonization between TSOs and balancing markets is necessary to ensure efficient, non-discriminatory and transparent exchange of balancing services. At the same time it is challenging and complex due to the variety of balancing systems and market arrangements in different countries [2, 3].

A set of Standard Products for balancing capacity and balancing energy will be defined [1, Art. 29] to facilitate exchange of balancing products in European balancing markets. The harmonisation of balancing markets and introduction of Standard Products will influence the way TSOs handle power imbalances in the future. To ensure efficient use of resources, ENTSO-E recommends the development of an algorithm to be used in a centralized activation process, the Activation Optimisation Function [1]. However, identifying the optimal use of resources is not straightforward when choosing between products which may have different prices, characteristics, and locations.

Optimization techniques and algorithms are useful for determining optimal solutions for system balancing. Nevertheless, the quality of the optimal solutions are dependent on the system characteristics. In other words, efficient use of resources requires not only operational integration, but also well-designed balancing products and markets. From an optimization point of view, system regulations and product characteristics are seen as constraints. Some constraints are necessary to obtain realistic solutions. Other constraints arise from the decisions on product and market design. In optimization, adding extra constraints will never lead to a better objective function value [4, p. 112]. Inflexible or superfluous requirements in product design will generally degrade the solution, i.e. lead to higher costs.

To avoid inefficient use of resources, product characteristics introducing inflexibility through constraints should be detected, investigated, and discussed along with their impact on efficiency. Although the Network Code on Electricity Balancing (NC EB) has not yet been approved by the Agency for the Cooperation of Energy Regulators (ACER), proposals have already been made for Standard Product definitions, including [5], which will be used for analysis throughout this report.

## 1.2 Problem Description

The main objective of this thesis is to develop an optimization model for activation of balancing energy. This model will be used to investigate the use and behaviour of Standard Products for electricity balancing. The optimization model uses deterministic imbalance forecasts and represents a proactive balancing approach.

The use and behaviour of Standard Products will be investigated and demonstrated using different operational situations, including

- Maintaining frequency during structural imbalances
- Restoring frequency following an unexpected generator outage
- Re-dispatch at coupling of different bid periods

The influence of changes in the Standard Product portfolio or activation requirements will also be investigated and discussed.

The Standard Products definitions used are a subset of the definitions proposed by ENTSO-E Working Group on Ancillary Services in September 2014 [5]. Real imbalance data from the Norwegian power system is used for the scenarios, together with a fictional set of bids with prices and volumes resembling the Nordic Regulating Power Market.

Throughout this thesis, the optimization model will commonly be referred to as *the Balancing Energy Activation Model*, or simply *the model*.

## 1.3 Outline and Scope of Work

The optimization model for balancing energy developed for this thesis originates from the work done in [6]. For the purpose of this thesis, several changes and additions were made. Even with its added functionality, the development of the model is not motivated foremost by the challenge of finding the most efficient solution to a real-world problem, but rather to better be able to understand Standard Products and their implications on operation from an optimization perspective. Thus the function and scope of the model is limited compared to the balancing systems used by some TSOs.

The Balancing Energy Activation Model will be developed to find optimal schedules for activation of balancing energy, taking into account a set of Standard Product definitions and a simplified representation of the power system and balancing market. The activation schedules obtained from the model for different scenarios will display how the solutions are influenced by changes in the model or the input data. The data sets and model parameters are chosen to be resembling balancing operations in Norway.

## 1.4 Report Outline

Chapter 2 contains background material on the the basic principles of frequency control, electricity balancing markets and operations. The final section of this chapter describes the integration of European balancing markets, and provide a political context for the investigation of Standard Products.

In Chapter 3, the methodology used for the research is described in detail, emphasising on the developed optimization model and its mathematical formulation. The chapter also includes information on the model implementation and the necessary input data. The final section introduce the different scenarios used for investing the behaviour of the Standard Products

The results from running the optimization model with the scenarios from Chapter 3 are presented in Chapter 4. The results are focused on the activation schedules for individual scenarios, as well as results regarding activation costs, volumes and duration. The results are discussed throughout Chapter 5. Included in this chapter is also a thorough discussion of the assumptions, simplifications and errors made in the model, and their impact on the validity of the results.

The most important observations and recommendations are summarized in Chapter 6.

# Chapter 2

# Background

## 2.1 Introduction

Electricity balancing is essential to maintain operational security in any power system. Although all systems are governed by the same laws of physics, the operational practices might differ significantly between countries and areas [2, p. 30], according to local policy and history. This is an obstacle in the process of market integration and the realization of an European Energy Union.

Although the entire diversity of balancing approaches can not be described in detail, the main underlying principles explained in Sections 2.2 and 2.3 are similar in many systems. It is the implementation of these principles through market and operations design that differ widely, as demonstrated in Section 2.4. Section 2.5 will outline the process of integrating the European balancing markets, including the introduction of Standard Products.

## 2.2 The Power Imbalance and its Causes

To ensure secure operation of the power system, there must be continuous balance between the amount of power consumed and generated. Mismatch between consumption and generation will lead to frequency deviations and may compromise the stability and integrity of the system and its components. Power generation is scheduled to match consumption using load forecasts, but even with increasingly accurate load forecasting techniques, imbalances still arise for different reasons, as explained in the following paragraphs. As a result, the power system needs to be continuously monitored and controlled in order to maintain the balance during normal operation or restore it quickly following an incident.

### 2.2.1 Forecast Error

In traditionally organized power systems, power consumption is considered as inflexible in the short term, and power generation is scheduled and controlled to closely match the level of consumption. Generation schedules are created using load forecasts, and when forecasts are wrong, there will be a mismatch between the actual level consumption and

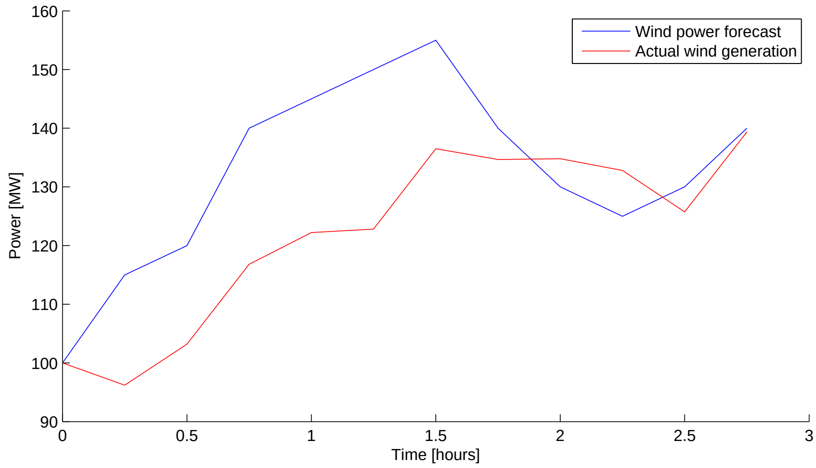


Figure 2.1: Example of a wind forecast error, causing an imbalance between actual and scheduled generation.

the scheduled generation. This is referred to as the load forecast error.

In addition, power generation from intermittent renewable sources introduces generation forecast errors. Especially for wind power, there is high uncertainty in forecasts for several hours ahead, as described in [7], leading to large generation forecast errors. Closer to real time, the accuracy of wind power forecasts improves, and generation schedules can be adjusted within a producer's portfolio or through intra-day markets, as discussed in [8]. Such adjustments reduces the impact of forecast errors on the power balance. Still, short term uncertainty and fluctuations is assumed to be a major source of imbalances in the power systems of the future following the increasing penetration of wind power. This will increase the need for balancing power reserves, according to [7], [9].

### 2.2.2 Structural Imbalances

Definition from [10]:

> Structural (or deterministic) imbalances are caused by the lack of coherence between on the one hand continuously varying demand and on the other hand scheduled changes of generation at the hour shifts.

Structural imbalances do not arise from uncertainty or inaccurate information, but simply from the different profiles of the continuous consumption variation and the more stepwise generation schedules. In addition, rapid flow changes on High Voltage Direct Current (HVDC) interconnections influence these profiles and contribute to structural imbalances. From a Nordic TSO point of view, new interconnections to the continent is expected to complicate operation even more [11, p. 63].

The issue arises especially during the morning and evening hours when consumption changes rapidly. Reducing the market clearing period from one hour to 15 minutes has been found to improve the coherence between consumption and generation schedules and thus reduce structural imbalances in the Nordic system [10].

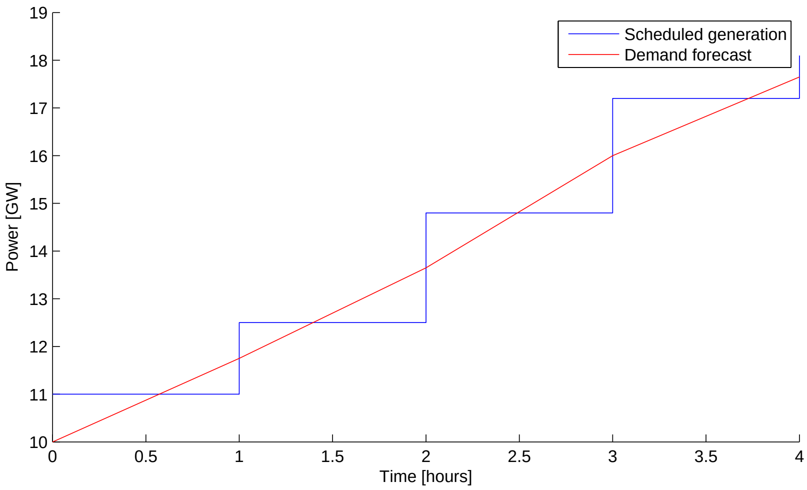


Figure 2.2: Example of an incoherence between scheduled generation and forecast demand, causing a structural (deterministic) imbalance.

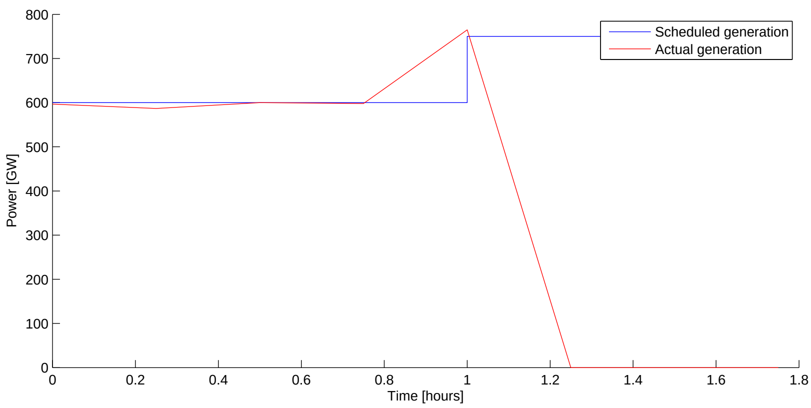


Figure 2.3: Example of an imbalance caused by a sudden generator outage, causing a large deviation from the generation schedule.

### 2.2.3 Outages

Unexpected outages cause sudden changes in the balance between consumption and generation. Should a generating unit be disconnected following an error, there will be a power deficit which must be covered. Similarly, connecting or disconnecting a large load or HVDC interconnections will also affect the instantaneous power balance.

In addition, outages in the transmission grid may change the directions of the power flow in such a way that power generation must be re-dispatched to ensure secure system operation. This is an issue particularly in cases of system congestion. Large unexpected generator outages occur infrequently, but the resulting large imbalance often determine the requirement on available reserve capacity to maintain secure operation. This is commonly referred to as the dimensioning fault.

### 2.2.4 Forecasting the Power Imbalance

As mentioned, the power imbalance is the instantaneous difference between generation and demand. An imbalance forecast may be calculated using forecast values for load, generation and cross-border exchange.

Load forecasting has been used for generation scheduling for several decades, and various techniques have been proposed and tested [12], as described in [13, p. 270]:

> Most forecasting methods use statistical techniques or artificial intelligence algorithms such as regression, neural networks, fuzzy logic, and expert systems. Two of the methods, so-called end-use and econometric approach are broadly used for medium- and long-term forecasting. A variety of methods, which include the so-called similar day approach, various regression models, time series, neural networks, statistical learning algorithms, fuzzy logic, and expert systems, have been developed for short-term forecasting.

The horizon of short-term load forecasting is usually from one hour to one week [13]. While the techniques are different, the main objectives are usually the same; to obtain an estimate of the extreme values, and to obtain a load profile for the given period, which can be regarded as a time series of load estimates.

Traditionally, generation is scheduled to match the load forecast, and may be rescheduled until a few hours before real-time operation as new forecasts are made. For intermittent generation, such as wind and solar power plants, generation schedules are based on weather forecasts. Traditional generating units, such as thermal and large hydro power plants, are scheduled to cover the forecast demand, less what is forecast to be generated from intermittent sources. The selection of generating units may be done in a traditional central scheduling process or implicitly through the use of a wholesale market. Due to the uncertainty in intermittent generation, the sum of scheduled generation from traditional and intermittent sources can be considered a generation forecast.

Exchange with other areas must also be considered. This includes both the Alternating Current (AC) exchange and exhange on HVDC interconnectors.

The forecast imbalance $\Delta \hat{P}_t$ at time $t$ can be found for an area as

$$\Delta \hat{P}_t = \hat{P}_t^L - \hat{P}_t^G - \hat{P}_t^X \tag{2.1}$$

where $\hat{P}_t^L$ and $\hat{P}_t^G$ are the forecast values at time $t$ for load and generation, respectively, while $\hat{P}_t^X$ is the net instantaneous power import from other areas.

Thus the imbalance forecast will change as the other forecasts are updated when approaching real-time operation.

## 2.3 Frequency Deviations and Control

### 2.3.1 System Frequency and Synchronous Operation

In power system terminology, a *synchronous area* denotes a geographical area in which generating units are rotating synchronously, i.e. the system frequency is shared. This is due to the fact that the flow of power in an AC power system is not fully controllable, but

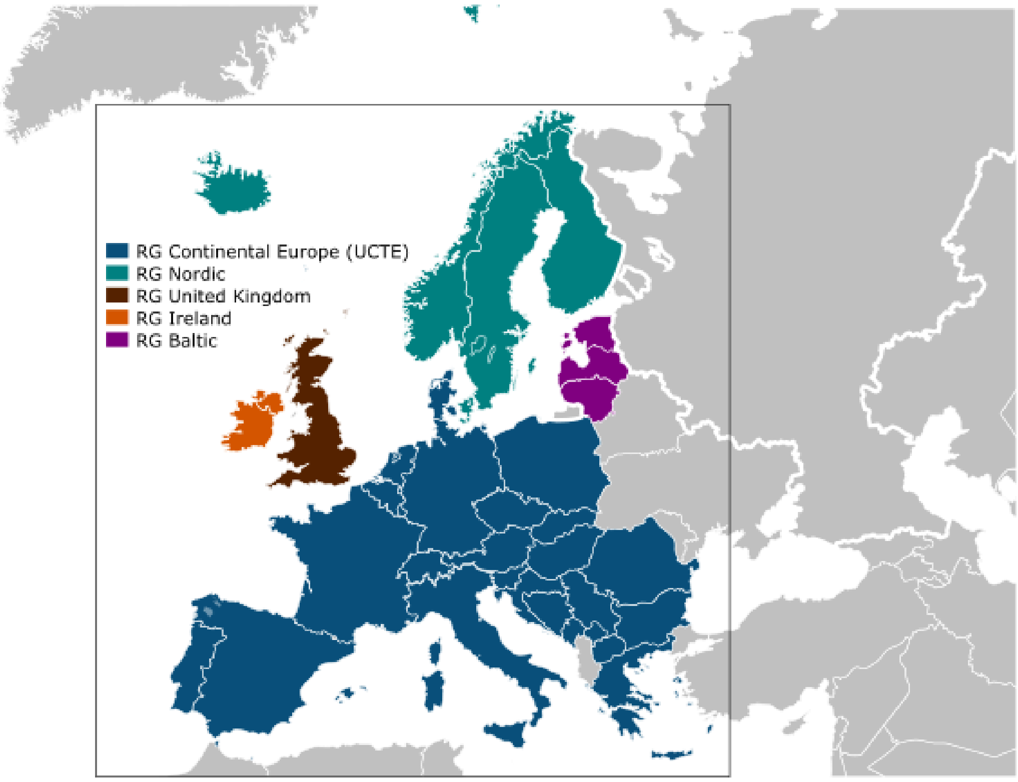


Figure 2.4: "The synchronous grids of Europe", by Kashmiri, used under CC BY-SA 3.0

rather directed primarily by the physical laws governing the system and the characteristics of the system components. Systems which are interconnected using AC transmission will operate synchronously. The flow of power on an HVDC interconnection, on the other hand, can be controlled and such interconnections enable exchange of power between different synchronous areas. Several HVDC interconnections have been constructed between the synchronous areas of Continental Europe and the Nordic countries, such as the 700 MW NorNed link between Netherlands and southern Norway.

### 2.3.2 Controlling the System Frequency

The system frequency is strongly connected to the balance between consumed and generated power in the system. Following the power-torque relation in Equation (2.2),

$$P = \tau\omega \tag{2.2}$$

a power imbalance $\Delta P$ between consumed and generated power will be equivalent to a torque imbalance $\Delta\tau$ when the rotational speed $\omega$ is close to 1.0 p.u. This torque imbalance $\Delta\tau$ is the difference between the mechanical torque from the turbines and the electrical torque applied by the load. According to Newton's 2nd law for rotational motion,

$$\Delta\tau = J\dot{\omega} \tag{2.3}$$

this torque difference will accelerate or decelerate rotation of synchronous generators by an amount $\dot{\omega}$, subject to the moment of inertia $J$ of the system. The system inertia is a physical parameter given largely as the sum of inertia of all individual synchronous machines rotating in the system. A torque imbalance will be distributed among the generators according to their inertia, causing approximately the same rate of acceleration on all units [14]. The high inertia in large interconnected power systems means frequency will accelerate slowly following a given imbalance, while the opposite is true in smaller systems. This acceleration will in principle continue as long as the imbalance persists. Removing the power imbalance would give a net acceleration of zero and stabilize the frequency at its current value.

The purpose of frequency control is to keep the system frequency close to the nominal value. Large frequency deviations may cause damage or erroneous operation, and some system components are disconnected automatically if the frequency goes outside a given range. Such disconnections would severely compromise the stability and security of system operation, and thus narrow ranges are defined for the frequency during normal operation and during contingencies. Frequency control can be seen as a part of the balancing process, as some of its stages directly employ techniques to cover or manage the power imbalance to stabilize (contain) and restore the frequency to the nominal value. It should, however, be noted that not all power systems use precisely the same control structure as presented in the following sections.

### 2.3.3 Frequency Containment Reserves and Primary Control

Frequency control can be divided into different stages, relating to their response time and intended duration. The first stage of control is often referred to as primary control, and intended to contain the system frequency following a disturbance. This is done using speed-droop control on some of the generators, i.e. controllers are made frequency sensitive. Generating units providing FCR may participate in primary control. Providing FCR requires having generation capacity available as spinning reserve, which for units in operation is defined as the difference between the power rating and the actual load of the unit.

The following derivation of speed-droop and frequency bias equations is based on [14] and [15].

Speed-droop control employs a closed-loop control structure, using the deviation from nominal frequency as the input to the turbine governor. For a negative frequency deviation, the controllers will increase the mechanical power, and vice versa. For each individual unit $i$ participating in primary, the power increase or decrease will be determined by the droop parameter $\rho_i = \frac{1}{K_i}$ on the turbine controllers as

$$\rho_i = -\frac{\Delta f P_{ni}}{f_n \Delta P_i}, \tag{2.4}$$

where, $P_{ni}$ is the nominal power rating and $\Delta P_i$ is the increase in power output of generating unit $i$, $\Delta f$ is the frequency deviation and $f_n$ is the nominal system frequency. A related parameter is the frequency bias $\lambda_i$ for the individual unit, calculated as

$$\lambda_i = \frac{\Delta P_i}{\Delta f} = -\frac{1}{\rho_i}\frac{P_{ni}}{f_n}. \tag{2.5}$$

The frequency bias describes the resulting change in power generation from unit $i$ from a frequency deviation $\Delta f$.

For a total of $N_G$ units within a control area participating in primary control, the aggregate frequency bias $\lambda_G$ from power generation is simply

$$\lambda_G = \sum_{i=1}^{N_G} \lambda_i. \tag{2.6}$$

When linearizing around $P_L$, we have that

$$\lambda_G = -K_G \frac{P_L}{f_n}, \tag{2.7}$$

where $K_G = \frac{1}{\rho_G}$ is a linearization constant corresponding to the inverse system-wide droop $\rho_G$ for the given level of demand. This parameter depends on the linearization point $P_L$ as $\rho_i = \inf$ for a generating unit running at maximum. It is calculated as

$$K_G = \frac{\sum_{i=1}^{N_G} K_i P_{ni}}{P_L}. \tag{2.8}$$

The system load is also frequency sensitive to some extent, primarily because of the speed-power characteristics of induction motors. The frequency bias $\lambda_L$ of the demand side can be found for a given load level $P_L$ as

$$\lambda_L = \frac{\Delta P_L}{\Delta f} = K_L \frac{P_L}{f_n}. \tag{2.9}$$

As the signs of the generation and load frequency biases are opposite, both sides will contribute to reduce the power imbalance and create a new equilibrium. Using Eqs. (2.7) and (2.9), the total aggregate frequency bias for the system at a given load $P_L$ can be written as

$$\lambda_R = \lambda_G - \lambda_L = -(K_G + K_L)\frac{P_L}{f_n} = -K_f \frac{P_L}{f_n}. \tag{2.10}$$

The constant $K_f$ is sometimes referred to as the stiffness of the system. The frequency bias $\lambda_R$ is given in MW/Hz and describes for an area with a given stiffness and power demand the power regulation from primary control as a function of frequency deviations. It should be noted that this parameter is only valid relatively close to the nominal frequency, i.e. within the range of FCR activation, typically within a few hundred mHz of the nominal frequency in most systems [14].

Using primary control, small imbalances are covered without significant change in frequency. For larger, persisting imbalances, however, some or all of the available FCR capacity may be exhausted, meaning additional imbalance in the same direction will not be counteracted by primary control. To free the FCR capacity and restore frequency, secondary reserves must be activated.

### 2.3.4 Frequency Restoration and Secondary Control

While frequency is stabilized to an equilibrium by the FCR, the purpose of Frequency Restoration Reserves (FRR) is to shift the point of equilibrium back to 50 Hz. These

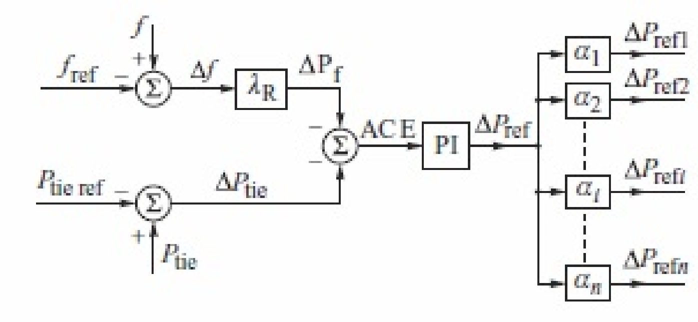


Figure 2.5: The use of ACE in secondary control [14, p. 343]

reserves are usually differentiated into aFRR and mFRR, corresponding to their respective mode of activation. System operators may use one or both kinds of reserve in the balancing process. mFRR has slower response time and is intended for longer duration than aFRR.

FRR restores frequency to 50 Hz by changing the power reference points on participating turbine governors. The reference point is chosen by the TSO and depends on the imbalance situation. Increasing power output during a negative frequency deviation will accelerate the system. As frequency increases, additional power output from primary control will decrease while demand increases somewhat. The amount additional power generation from secondary control necessary to restore the frequency is given by the frequency bias $\lambda_G$ (from Eq. (2.10)) and deviation. At this point, power generation equals demand using only the power adjustments from secondary control.

The activation time of aFRR is generally short, typically 2-3 minutes in the Nordic system, and 5-10 minutes on the European continent. Activation of mFRR is generally slower, partly due to manual control actions.

### 2.3.5 Replacement Reserves and Tertiary Control

RR is used to relieve exhausted FRR capacity. Activated RR introduces new power generation into the system, replacing the temporary increase delivered from secondary control using FRR. This could be necessary in cases of persisting imbalances, typically following outages or significant forecast errors. The activation of RR is referred to as tertiary control. RR may include generating units not currently running, and activation times and duration are generally longer than for mFRR.

### 2.3.6 Area Control Error

The  mechanism allows a simultaneous combination of frequency control and tie-line control, and is widely used for secondary and tertiary control in interconnected power systems. Using Area Control Error (ACE), an imbalance originating in a given area will be covered using reserves from the same area. This is generally achieved by managing the power references given by secondary control, which using ACE will be controlled to match the power imbalance after deviations from scheduled tie-line flows are taken into account [14]. A typical arrangement is shown in Figure 2.5.

The signals change in power reference $\Delta P_{ref,i}$ for the individual units $i$ are found using participation factors $\alpha_i$. The ACE signal is simply a combination of the tie-line error $\Delta P_{tie}$ and the power imbalance $\Delta P_f$ corresponding to the frequency error $\Delta f$, where $\Delta P_f = \lambda_R \Delta f$.

$$\text{ACE} = -\Delta P_{tie} - \lambda_R \Delta f \tag{2.11}$$

The combination of frequency and tie-line errors prevents other areas from covering the imbalance through secondary control. As the frequency is shared by the entire synchronous area, FCR will be activated for all participating units, but through the use of ACE, secondary control will restore both frequency and tie line flows. The integral element of the PI controller will also compensate for past imbalances.

### 2.3.7 Reactive and Proactive Approaches

Strategies for covering imbalances can be roughly categorized as *reactive* or *proactive* approaches. Reactive methods are based on observing imbalances or frequency deviations and responding by delivering balancing power. Proactive methods, on the other hand, are based on predicting imbalances and plan in advance the necessary delivery of balancing power.

Both approaches have strengths and weaknesses. Reactive methods can easily be automated to handle imbalances using simple control loops, while implementing proactive methods is more comprehensive. A proactive approach may enable better coherence between demand and generation, but at the same time relies on the quality of the forecast.

## 2.4 Balancing Power Markets and Operations

### 2.4.1 Organization of the Electricity Sector

Since the 1990s, electricity sectors have been deregulated in many countries. Before this, power systems were typically operated as vertically integrated utilities, responsible for both generation, transmission and distribution of electricity [15]. Typically, generating units were scheduled and dispatched centrally following a cost minimizing optimization.

A motivation for the deregulation of power sectors over the last few decades has been to increase efficiency and social welfare using competitive markets [15]. Today, competing power retailers purchase electricity from competing power producers through the use of of bilateral contracts or a power exchange. Electricity transmission is, however, often regarded a natural monopoly [16] due to the fixed costs involved. In [15, p. 76], it is claimed that even though the economy of scale is questionable, the purposes of operational coordination favours a single transmission operator arrangement. Distribution is traditionally regarded a natural monopoly [15], [16], [17]. The introduction of new business models and network structures, such as micro grids, or even off-grid systems using distributed generation, challenges the monopolistic position of distribution system operators [18], [19].

### 2.4.2 Electricity Markets

Electricity market arrangements differ between countries. In Europe, there has been a trend of coupling and merging wholesale electricity markets of different areas. One example is the Nordic day-ahead market, which is operated by Nord Pool. Nord Pool was established in 1993 as a Norwegian power exchange, extended in 1996 to include Sweden, soon also Denmark and Finland [15]. In addition to the day-ahead ELSPOT market clearing, Nord Pool also operates intra-day trade through the ELBAS market. Following a cooperation between TSOs and power exchanges of France, Belgium, the Netherlands and Germany, the Central Western Europe (CWE) market coupling was launched in 2010 using an Available Transfer Capacity (ATC) based approach. In May 2015, the newly developed flow-based solution was launched, allowing better allocation of cross-border capacity.

These are examples of tight market coupling. In addition, cross-border exchange of power provides an additional loose coupling between different markets, such as in the case of the NorNed HVDC interconnection between Norway and the Netherlands. There are also futures and forwards markets for electricity. In these markets, purely financial electricity contracts are traded bilaterally for months or even years ahead.

In addition to the wholesale electricity markets, there may be separate markets for balancing purposes. The exact market arrangements differ between areas according to the operation of the system. Many of the terms described below are, however, applicable for most Northern European systems [3], although the terminology may be different.

### 2.4.3 Firm Capacity Contracts and Reserves Activation Markets

As described in Section 2.3, different kinds of reserves are employed for the different stages of frequency control. Liberalized electricity systems have separate markets or contracts for provision and use of different reserves.

FCR and aFRR are usually procured periodically using firm capacity contracts, i.e. producers are obliged to provide the contracted reserve capacity during the contracted hours. Firm capacity contracts may also be used for manual reserves, such as mFRR and RR in order to ensure sufficient reserve capacity. Firm capacity payments may provide income to generating units not able to compete on the wholesale market. Contracts may be traded bilaterally or via a pool.

In addition to the firm capacity markets, there are often separate activation markets for balancing energy. These markets often apply only to manual reserves. When reserve capacity is needed during real-time operation, the provider of the activated reserve will receive compensation during settlement for the provided balancing energy. The pricing method differs between areas, but is usually given either by the bid price for the provided energy (pay-as-bid) or the bid price of the most expensive unit activated (marginal pricing). In both cases, bids will generally be activated in the order of increasing marginal cost (merit order) or pro rata, i.e. simultaneously to an extent decided by their available capacity.

### 2.4.4 Market Participants

As described in [3, p. 17], there are three main participants in liberalized markets for balancing services. The TSO is responsible for procuring and employing balancing services. Bids for balancing services are submitted by Balancing Service Providers (BSPs) during the procurement phase for the different kinds of reserve capacity, as described in Section 2.4.3. During real-time operation, the TSO may activate balancing energy from the manual activation market to cover an imbalance. During the imbalance settlement phase, Balance Responsible Partys (BRPs) are charged by the TSO for their metered deviation from their power generation and consumption schedules. The deviation penalty is called the imbalance price and differs between different markets. BSPs are paid by the TSO using some of the income from the imbalance settlement.

### 2.4.5 The Costs of Electricity Balancing

The bid prices provided by the BSPs reflect their costs of balancing services. Wangensteen [15, p. 289] states that the cost of providing active reserves consists of operational costs and opportunity costs. The operational costs will determine bid prices in the balancing energy markets, as they reflect the costs of using fuel or stored water for delivering energy. They may also incorporate the operational cost of running on hot standby to provide reserve capacity.

The prices in firm capacity markets will be decided mainly by the opportunity costs. Such costs arise when providing reserve capacity prevents running at the optimal level of generation. The optimal level of generation could perhaps be zero or at full capacity. The lost income from running at a suboptimal schedule to provide reserve capacity is reflected in the opportunity cost. Opportunity costs should also include the risk related to contracting fixed capacity without certainty of future prices. A methodology for estimating opportunity costs for bidding in the FRR market is shown in [20].

### 2.4.6 Operating the Balancing Markets

Balancing markets are often operated by the TSO of the given area. For the procurement phase, the TSO determines the necessary amount of reserves to be purchased through firm capacity contracts. The TSO decides which bids are accepted taking into account bid prices and system contraints.

While many power systems are now operated using self dispatch, balancing operations are handled centrally by the TSO in most countries. This means that during real-time operation, the TSO acts as a player in the activation market as bids for balancing energy in upwards or downwards regulation are traded between the TSO and the BSPs.

### 2.4.7 Balancing Markets and Operations in Norway

In Norway, the TSO operates the balancing markets. This includes both the procurement of required reserve capacity and real-time activation of balancing energy. In this thesis, the Nordic power system serves the most important context for the analysis of new market arrangements. To illustrate some of the regional differences in market design and operations, an overview of the balancing processes in Great Britain, as well as a brief introduction to the Dutch approach to balancing have been included in the subsequent sections.

### Frequency Containment Reserves

Two different products are procured for FCR [21]. Frequency Controlled Normal Operating Reserves (FCR-N) respond to frequency deviations in the normal operating range, which is between 49.9 and 50.1 Hz. Frequency Controlled Disturbance Reserves (FCR-D) are intended for larger disturbances and are activated should the frequency fall below 49.9 Hz. The entire amount of FCR-D is activated at the Nordic lower frequency limit of 49.5 Hz. Markets for FCR-N and FCR-D are cleared on a daily basis, while there is also a weekly market clearing for FCR-N. Typically, about 600 MW of FCR-N and 1200 MW of FCR-D is procured for the Nordic system in total.

Both generation and consumption units can participate in the auctions for FCR capacity. Bids are primarily accepted in the order of increasing bid price, and receive the bid price of the marginal unit within the same area [21]. For the daily procurement prices are given on a hourly basis, while for the weekly procurement, market clearing periods are aggregated with discrimination between weekdays and weekend, as well as night, day or evening.

The amount of FCR provided by a unit is determined by the droop parameter on its controller. For units above 10 MVA, a maximum droop setting of 12 % (6 % during the summer season) is required even if not accepted in the FCR market.

### Frequency Restoration Reserves with Automatic Activation

In the Nordic countries, only aFRR is now considered a part of secondary control, and its main purpose is to support frequency. aFRR was introduced in the Nordic system in 2013, while the use of ACE was abolished in 2002 [22]. aFRR is only procured for the morning and evening hours, with a procurement volume was 300 MW in 2015. This volume is shared between countries according to their annual consumption.

Statnett procures capacity for aFRR for weekly blocks and on a weekly basis [23]. It is employed in real-time using an Load and Frequency Control (LFC) mechanism. Providers receive a capacity payment given by the marginal bid price in the given area. For activated energy volumes, providers also receive a compensation given by the imbalance price, which again is determined by the activation of manual reserves. The activated aFRR volume does not affect BRP imbalances, as it is settled in a separate market arrangement.

The technical requirements for aFRR providers is given in [24]. Provides must be able to deliver the required power within 120 seconds, with a maximum step size of 20 MW for each provider. This includes a maximum delay of 30 seconds. The maximum duration for a single set-point is 30 minutes, but there is no limit on the duration of activation in one direction.

### Frequency Restoration Reserves with Manual Activation

mFRR is considered a part of tertiary control in the Nordic system. These reserves are mainly used for relieving the aFRR and for relieving bottlenecks within areas. In this sense, the mFRR may also take the role of RR in some cases.

The amount of mFRR procured by each of the Nordic TSOs depends on the dimensioning fault in each area, which is 1200 MW in Norway. Statnett even procures an additional 500 MW to be able to manage regional bottlenecks and imbalances.

During real-time operation, mFRR bids are activated manually from the Statnett control centre, and the Regulating Power Market (RPM) [25] is used as an activation market for manual reserves. Bids used for frequency restoration and support will be activated in the order of marginal cost, and the imbalance price will be determined by the marginal unit participating activated. Reserve activation necessary due to congestion is considered an exception and will not determine the imbalance price. BSPs will in these cases be compensated for balancing energy using a pay-as-bid method.

To avoid insufficient capacity in the Norwegian part of RPM, firm capacity contracts are made through the Regulating Power Options Market (ROM). If accepted in ROM, the producer is obliged to place bids for the contracted capacity in RPM for the given period. In return, the producer receives a compensation based on the price of the marginal bid accepted in ROM, the amount of reserve guaranteed, and the contracted period. ROM is used during the winter season, with the options market being cleared on a weekly basis. In addition, the options market is cleared for the entire winter season with accepted bids obliged to bid contracted capacity into RPM for the entire period.

In ROM, bid prices should reflect the cost of having available capacity during the given period. This cost may have an operational element related to keeping units on hot or cold standby, as BSPs providing bids to the RPM must be able to deliver the activated amount of power within 15 minutes [25]. The price of a bid in ROM should also reflect the opportunity cost of not being able to use the contracted capacity elsewhere. This is roughly equivalent to the expected profit of having the same capacity free for sale in other markets.

As electricity prices in Norway have been low in recent years, producers with high marginal costs, such as gas power plants, will rarely, if ever, have their bids accepted in the spot market. In such a case of low expected revenue and opportunity cost, the capacity payment received from providing generation capacity will be more profitable. For the seasonal clearing of ROM for 2014/15, Statnett purchased a volume of 749 MW at the price of 8 NOK (0.95 €)/MWh, rougly 3 % of a typical system price in the spot market.

### Generation Schedule Shifting and Generation Schedule Smoothing

To efficiently handle the structural imbalances experienced in the Nordic system, the Nordic TSOs employ the *load following* ancillary service [26], sometimes also referred to as generation schedule shifting. This mechanism allows adjustments in the start-up times of generating units by up to 15 minutes. Decisions on if and how generation schedules should be shifted are made by the engineers at the control centre during real-time operation. This enables better coherence between generation and demand without using mFRR activation. Producers are compensated for the schedule shift using the spot price or the price set by the RPM, depending on which is favourable.

In June 2015, Statnett will introduce a new service for generation schedule smoothing [27]. This service has similarities to generation schedule shifting, in that it will adjust start-up times of generation schedules to follow demand more closely. Generation schedule smoothing will, however, be employed several hours in advance of real-time operation, using an algorithm to detect large structural imbalances and suggest schedule adjustments. The algorithm is developed by Bjørn H. Bakken, and allows schedule adjustments up to 30 minutes.

### 2.4.8 Balancing Market and Operations Practices in the UK

When the electricity sector in the United Kingdom (UK) was privatized and deregulated in the early 1990s, National Grid (NG)emerged as a TSO from its ancestor, theCentral Electricity Generating Board (CEGB). Today, NG is not allowed to own generation facilities in Britain, and while large parts (England and Wales) of the transmission networks are owned by NG, the system operation resembles that of an Independent System Operator (ISO), i.e. as if the transmission grid was owned by an external party [28].

**Reserves and Balancing Markets**

There is no day-ahead market clearing in the UK market. Market participants, such as power producers and retail suppliers, trade bilaterally until Gate Closure Time (GCT), which is 60-90 minutes before real-time operation. An important term in the balancing process is the Balancing Mechanism Unit (BMU), which is used for trade within the balancing mechanism. A BMU is typically a physical generator or group of suppliers larger than 100 MW. The HVDC interconnectors are also considered BMUs for this purpose, using a separate market arrangement.

BMUs participate in the balancing process by providing prices for separate generation levels of upward and downward regulation from their scheduled generation, which is called the physical notification. The upward and downward prices are called *bids* and *offers*, respectively. After the GCT, NG can issue instructions to BMUs to increase or decrease generation for a given duration within the gate closure window. Such an instruction is called a Bid Offer Acceptance (BOA). This is a pay-as-bid arrangement, and during settlement, the BMU is compensated for participating in accordance with its submitted prices and the metered level of generation.

NG does its own forecasts for the generation and consumption of BMUs. In some cases the physical notifications of BMUs will not provide sufficient margins for upwards and downwards regulation, e.g. due to inaccurate forecasts. Usually, the market solves such problems by itself. NG is, however, allowed to trade in the market if necessary to maintain secure operation [29].

Sufficient ancillary services are ensured through the reserve determination process. The NG system does not use Automatic Generation Control (AGC), but relies on the use of BOAs together with a few different services for governor response. Units on governor response cover the faster imbalances, and are paid to be available, to deliver response and for the energy delivered. Typically, about 10 units are on governor response, out of about 100 operating BMUs [28]. Some of the firm services are procured a month ahead, while the majority of response is allocated in real time by the dispatching tool, from BMUs available in the market. In addition, Short Term Operating Reserve (STOR) contracts are procured 3 times a year. These generating units are paid to be available 85 % of the time during peak periods, not entirely different from the Nordic Reserves Options

Market.

### Forecasting the Imbalance Situation

Forecasting is key to the NG proactive balancing operations approach. The use of forecasts enable reserve activation decisions to be made in advance through the BOAs mechanism.

Demand forecasts have been used for a long time. Rather than demand, however, the amount of *required generation* is the important factor when determining generation levels. Forecasting is done through the Electronic Forecasting System. This system uses years of data, the most important input factors being weather (temperature, rain, wind speeds etc.) and light conditions, for which the regression factors are calculated. Forecasts are generated for several hours ahead up to seven days using Auto-Regressive Integrated Moving Average (ARIMA) models and off-the-shelf econometrics packages [29]. Wind and solar use time series forecasts. For the demand, a cardinal points approach is used, meaning a profile from a relevant, similar day is stretched to fit a given set of turning points. Every three hours during the day, a 4 hour ahead weather based forecast with 5 minute granularity is updated. In addition, an online forecast is made once per minute based solely on actual metered generation. This forecast blends with the longer term weather-based forecasts.

In addition to forecasting the generation requirement, the maximum and minimum required generation needs are also forecast for reserve capacity purposes, together with seven different varieties of governor response. Reserve requirements are based on statistics relating to forecast errors, errors in following instructions and plant failures, and vary according to lead time and risk.

While short-term forecasts have the purpose of controllability, NG also perform long-term (10-30 years) forecasts [30]. These use GDP and population and customer demand growth to investigate how the power system will and should evolve.

### Real-time Balancing Operations and the Electricity Balancing System

After five years of development, NG will in 2016 introduce the Electricity Balancing System (EBS), a new and comprehensive tool for balancing operations. NG claim it will probably be the most sophisticated balancing system in the world [30]. The EBS is a completely data-driven tool, gathering all relevant market data, such as bid and offer prices and the different forecasts. Using optimization, the system outputs a set of advices on changes in BOAs to balance the system at lowest cost.

The system uses four different optimizer stages [31] [32]. The first one, the Day-Ahead Schedule, is independent from the last three, and used to get an overview of the future power situation, providing decision support on whether NG should participate in trade to reduce future imbalances. The second optimizer stage, the In-Day Schedule, creates a schedule up to 23 hours ahead and takes most of the commitment decisions. It has a granularity of 30 minutes, and uses a convergence loop to ensure secure operation of the network. The unit commitment decisions are passed on as sunk decisions to the third optimizer, which is the Real-Time Commitment. It is run every 15 minutes for the period from 30 minutes to four hours ahead. Unit commitment decisions can be changed in this stage if it is possible within the time window. The granularity is 5 minutes until GCT, and 15 minutes for the rest of the period.

The final optimizer stage is the Real-Time Dispatch. Its horizon is from ten minutes to four hours ahead. It uses the market data and unit commitment statuses to generate advice for BOA instructions to balance the system. The number of instructions can be limited in order to avoid sending BMUs an overwhelming amount. Currently, instructions are sent trough a manual electronic dispatch by the control engineers of NG, while the EBS supports full automatic broadcasting of instructions based on the advice from the optimizers.

Algorithms are designed to reduce the amount of excessive instructions, such as reversing earlier decisions. This includes a coupling the advice algorithm with a tool determining whether the advice should be issued as an instruction.

### 2.4.9 Balancing Market and Operations Practices in the Netherlands

#### Procurement of Reserves

Earlier, Dutch TSO, TenneT, did not procure primary reserves based on an economic selection process [33], instead all generators above 5 MW were obliged to deliver primary reserve. Market based procurement of FCR was introduced in the Netherlands in 2014, and in April 2015, this market was coupled with the corresponding procurement markets in Germany, Switzerland and Austria [34].

Secondary and tertiary reserves are procured through the use of long-term firm capacity contracts, as well a short-term (daily) decision process on using a price ladder. Any of these parties can be called to provide energy during real-time operation [33].

#### Real-Time Operation

The Dutch balancing energy market design differs from many other European countries. As for many other systems, the imbalance prices are determined for each Program Time Unit (PTU) by the marginal prices of the necessary upward and downward regulation from the TSO to keen the system in balance. As BRPs must pay this price as a penalty for each MWh deviated from the schedule, there is an incentive to provide accurate schedules, or even over-contracting capacity in order to reduce their deviations [35].

The TSO broadcasts the imbalance in real-time, thus BRPs are able to respond through internal balancing, reducing total imbalance volumes. [36] claims that this mechanism is sub-optimal, as BRPs tend to self-balance too much. The result is in either case that balancing energy volumes, imbalance prices and actual BRP costs have been found to be much lower compared to e.g. Germany [35], as the market itself covers parts of the imbalances during real-time.

When the participation from BRPs is not sufficient to cover the system imbalance, or in cases where the market over-compensates, the TSO activates bids for balancing energy to keep the system in balance.

## 2.5 Integration of European Balancing Markets and Operation

### 2.5.1 An Internal Electricity Market for Balancing

The European Union has set ambitious targets for emission reductions, energy efficiency and and renewable energy generation through the 2030 Framework for Climate and Energy [37]. This framework was agreed on by the European Council in October 2014 and addresses the issue of climate change. In addition, there is strong political will to reduce the dependency on importing energy from outside the union.

In this ambition of making the European Union an *energy union*, an important objective is achieving fully functional and connected internal energy markets [38]. Existing energy markets should not only be integrated, interconnection capacity for electricity transmission shall also be increased. In [37], the European Council concluded that all member states should have the infrastructure to import or export 15% of its generation capacity by 2030. The increased interconnection capacity will not only provide opportunities for exchange on the wholesale market, but also for exchange of balancing services. Capacity could be pre-allocated for exchange of balancing services or sharing of reserves, as proposed in [39] and [40], but [41] suggests otherwise.

### 2.5.2 Harmonization and Integration of Balancing Markets and Operations

The Network Codes currently being developed by ENTSO-E will define rules which aim to facilitate integration of European electricity markets. Many of the European wholesale electricity markets have already been coupled, enabling power exchange between areas, e.g. through implicit auctions of interconnection capacity.

[42] claims there is a socio-economic benefit of integrating regulating power markets in Northern Europe. [43] found a cost decrease for the case of integrating the balancing markets in Germany, Austria, and Switzerland, but also a distributional effect. As the integration requires harmonization of market rules between countries [2], the Network Code on Electricity Balancing [1] specifically addresses market issues related to cross-border exchange. It emphasizes on harmonization of practices in imbalance settlement, such as imbalance calculation, pricing, settlement periods and mechanisms, as well as the need for harmonization of products for balancing energy and balancing capacity.

#### Coordinated Balancing Areas

When the Network Code is approved, TSOs from different member states will form Coordinated Balancing Areas (CoBAs). In [1, p. 10], a Coordinated Balancing Area means a cooperation with respect to the Exchange of Balancing Services, Sharing of Reserves or operating the Imbalance Netting Process between two or more TSOs. Within the CoBA, TSOs will jointly apply balancing principles, methodology, and market structures facilitating the exchange of balancing services, sharing of reserves and operating the imbalance netting process. This also includes methodology for the Activation Optimisation

Function, such as the principles for the algorithm, the different Common Merit Order Lists (CMOLs), and the Standard Products for balancing energy.

Integration will be done using an evolutionary approach through the creation of CoBAs. This will be a continuous process of learning and harmonisation. [1, Art. 12(1)] states:

> All TSOs shall cooperate in promoting the extension and merging of Coordinated Balancing Areas in order to develop and implement the regional integration models and European integration models.

In the long run, one single, fully integrated CoBA would enable exchange of balancing services between all European TSOs. The increased competition aims to reduce market power and enable more efficient use of balancing resources.

While the Network Code on Electricity Balancing focuses on the market arrangements of cross-border exchange, the closely related Network Code on Load-Frequency Control and Reserves [44] provides additional details on operations, such as implementation requirements for the cross-border FRR activation process [44, Art. 37] and the relations to the LFC blocks and areas.

### The Activation Optimization Function

The Activation Optimization Function will enable cross-border exchange of balancing energy. During real-time operation, this function will determine the activation of balancing energy. [45, p. 20] outlines the important steps in this process:

> The steps involved in the activation of Balancing Energy are as follows:
>
> 1. TSOs send their requirements to the Activation Optimisation Function.
> 2. After the Balancing Energy Gate Closure Time, the Activation Optimisation Function calculates the most efficient activation taking the following into account:
>    - Common Merit Order List containing all Balancing Energy bids
>    - Available cross-border capacity either available after Intraday or reserved previously
>    - Network stability constraints
>    - Balancing requirements of the TSOs
>    - Imbalance Netting potential
> 3. Activation Optimisation Function sends the individual activation amounts (as a correction signal) to each responsible TSO (Connecting TSO).
> 4. The Connecting TSO activates the successful Balancing Energy bids (via a phone call or automatically by activation system such as a MOL-Server or local controller).
> 5. Balancing Energy is exchanged through commercial schedules or virtual tie-lines.
> 6. Balancing Energy is settled between the providers and the TSOs involved.

These steps explain the main principles behind the Activation Optimization Function, as proposed in the [45]. Efficient use of resources is achieved by comparing bids from different areas in a CMOL, allowing the least expensive ones to be activated. The need for activation will be determined by the requirements of TSOs and the potential for imbalance netting.

The algorithm used by the Activation Optimization Function will be jointly developed by the TSOs of the CoBA, i.e. the details in optimization will not be determined by the Network Codes alone. Although the steps outlined in [45] resemble a reactive balancing approach, they do not disqualify a proactive algorithm using forecasts and possibly scheduled activation.

### 2.5.3 Standard Products

Following the entry into force of the Network Code on Electricity Balancing, the TSOs of a CoBA to agree on a set of Standard Products for balancing capacity and balancing energy. These products are to be used and exchanged within the CoBA. Bids for balancing energy must meet a set of characteristics as described by the Standard Product definitions. Such bids will be made available for activation through the use of CMOLs and the Activation Optimisation Function. The use of Specific Products will also be allowed within areas, though somewhat differently, as described in [1, Art. 30].

The Standard Product definitions shall set specific values or ranges for different bid characteristics. [1, Art. 29] states:

> 5. The list of Standard Products for Balancing Capacity and Standard Products for Balancing Energy shall define at least the following standard characteristics of a bid by a fixed value or an appropriate range:
>
> (a) Preparation Period;
>
> (b) Ramping Period;
>
> (c) Full Activation Time;
>
> (d) minimum and maximum quantity;
>
> (e) Deactivation Period;
>
> (f) minimum and maximum duration of Delivery Period;
>
> (g) Validity Period; and
>
> (h) Mode of Activation.
>
> 6. The list of Standard Products for Balancing Capacity and Standard Products for Balancing Energy shall also define additional characteristics. The values of these additional characteristics are provided by Balancing Service Providers when submitting Balancing Capacity bids or Balancing Energy bids or for Prequalification or when requested by the TSO according to terms and conditions related to Balancing pursuant to Article 27. The additional characteristics shall at least include:
>
> (a) price, positive, 0 or negative, of the bid;
>
> (b) divisibility

Table 2.1: Characteristics of proposed Standard aFRR balancing energy products [5]

| | **aFRR1** | **aFRR2** | **aFRR3** | **aFRR4** |
|---|---|---|---|---|
| Preparation period | $\leq$ 30s (requirement from LFCR network code, see §3.4.2) | | | |
| Ramping period | N/A | | | |
| Full activation time | $\leq$ 2.5 min (precised by BSP) | $\leq$ 5 min (precised by BSP) | $\leq$ 7.5 min (precised by BSP) | $\leq$ 10 min (precised by BSP) |
| Deactivation period | | | | |
| Min. bid size | No more than 5 MW | | | |
| Max. bid size | 9999 MW | | | |
| Divisibility | Divisible in terms of power (1 MW) | | | |
| Min. delivery period | N/A | | | |
| Max. delivery period | $\geq$ balancing time period (to be defined by BSP) | | | |
| Price | Bid prices defined by BSP | | | |
| Location | At least bidding zone, to be defined by TSO if needed | | | |
| Validity period | N/A | | | |
| Recovery period | To be defined by BSP | | | |

(c) location; and

(d) minimum duration

The definitions of Standard Products have not yet been decided. In [5] from September 2014, a set of definitions is proposed. The definitions include products for aFRR, mFRR, and RR, as shown in Tables 2.1 and 2.2. As explained in [5], the product definitions in Table 2.2 can be regarded either as mFRR or glsrr depending on the time to restore frequency in different synchronous areas. Both the definitions and total number of Standard Products are still being discussed, and any final proposal for Standard Product definitions has not yet (as of June 2015) been forwarded for regulatory approval.

Table 2.2: Characteristics of proposed Standard mFRR and RR balancing energy products [5]

| | P1 | P2 | P3 | P4 | P5 | P6 | P7 | P8 |
|---|---|---|---|---|---|---|---|---|
| Preparation period | Defined by TSOs of the CoBA | | Defined by BSP | Defined by TSOs of the CoBA | | | | |
| Ramping period | | | | | | | | |
| Full activation time | 15’ | 15’ | | 10’ | 5’ | 15’ | 30’ | 15’ |
| Deactivation period | 15’ | 15’ | | 10’ | 5’ | 15’ | 30’ | 15’ |
| Min. bid size | No more than 5 MW | | | | | | | |
| Max. bid size | 9999 MW | | | | | | | |
| Divisibility | Defined by BSP (yes/no) | | | | | | | |
| Min. delivery period | 15’ | 30’ | 1’ | 5’ | 5’ | 15’ | 15’ | 15’ |
| Max. delivery period | To be defined by BSP, at least minimum delivery period | | | | | | | |
| Activation principle | Direct activated | | | | | Scheduled | | |
| Price | Bid prices defined by BSP | | | | | | | |
| Location | At least bidding zone, to be defined by TSO if needed | | | | | | | |
| Validity period | To be defined by BSP, at least minimum delivery period | | | | | | | |
| Recovery period | To be defined by BSP, optional | | | | | | | |

# Chapter 3

# Methodology

## 3.1 Introduction

As is stated in the Problem Description in Section 1.2, the use of Standard Products for electricity balancing is investigated using the Balancing Energy Activation Model. This model has been developed specifically for this purpose and its mathematical formulation is described in detail in Section 3.2. The notation used in the model is described in Section 3.3. A short introduction to its implementation is included in Section 3.4. While some of the simplifications made in modelling will be mentioned throughout these sections, their impact on model behaviour and results will be discussed in Section 5.2.

The optimization model uses three important sources of data. The use of imbalance forecasts is explained in Section 3.5, The Standard Product definitions are shortly described in Section 3.6 and in Section 3.7, the bids representing the manual reserve activation market are introduced and explained. Finally, Section 3.8 introduces the scenarios run by the model to obtain the results in Chapter 4.

## 3.2 Model Formulation

The optimization model for activation of balancing energy is a further developed version of the optimization model described in [6]. It represents a proactive balancing approach and has a structure resembling general unit commitment and dispatch optimization models for power scheduling. [46] summarizes the unit commitment problem well:

> Unit Commitment (UC) is the problem of determining the schedule of generating units within a power system subject to device and operating constraints. The decision process selects units to be on or off, the type of fuel, the power generation for each unit, the fuel mixture when applicable, and the reserve margins.

The balancing energy activation model is formulated as a Mixed Integer Linear Programming (MILP) model, meaning it can be formulated mathematically using continuous or integer decision variables and only linear constraints. An optimal solution is set of values for the different decision variables giving the lowest total cost while also satisfying all constraints. The constraints occur from the characteristics of the bids, products and the power system. A MILP structure was chosen due to the abundance of well-developed formulations for unit commitment problems, beginning with Garver [47] in 1962. The MILP structure also allows elegant constraint formulations for the different Standard Product characteristics.

### 3.2.1 Objective Function

The objective function to be minimized is given in Eq. (3.1) as the sum of activation and penalty costs. The activation costs are given as the sum of costs from upward and downward regulation over the time window, calculated as shown in Eq. (3.2). The cost of upward regulation is given by the bid price $c_b$ and activation volume $y_{b,t}$ for each individual bid $b$ and time step $t$. For downward regulation, the activation volume is multiplied with the difference between the spot price $p^{spot}$ and the price of the bid.

As the purpose of activating balancing energy is to cover imbalances and restore frequency, a good solution proposed by the model should take the resulting frequency into account. Frequency deviations are used as a measure of the quality of the balancing power activation schedule. Adding simple constraints on system frequency boundaries would not necessarily restore the frequency back to 50 Hz. In addition, such *hard* constraints lead to problem infeasibility in cases with large imbalances.

For this model, adequate frequency is therefore ensured by imposing a large penalty on frequency deviations, rather than constraining the allowed range. This gives the model an incentive to fully restore the frequency, while also making sure all problem instances have feasible solutions.

The frequency deviation penalty costs are calculated for each time step and depend on the estimated deviation from the nominal frequency and the marginal penalty level $p_k$, which increases for deviations larger than 0.1 Hz, as described in Section 3.2.3. The impact on model behaviour and results from using penalty costs is discussed in Section 5.2.4.

$$\min Cost = Cost^{act} + Cost^{pen} \tag{3.1}$$

$$Cost^{act} = \frac{LT}{60} \sum_{t \in T} \left( \sum_{b \in B_u} c_b y_{b,t} + \sum_{b \in B_d} (p^{spot} - c_b) y_{b,t} \right) \tag{3.2}$$

$$Cost^{pen} = \sum_{t \in T} \sum_{k \in K} p_k (f_t^{ok} + f_t^{uk}) \tag{3.3}$$

### 3.2.2 aFRR Activation

The implementation of aFRR activatin is simplified, and will be discussed in Section 5.2.3. The decision variable $x_t$ is the estimated aFRR activation at time $t$. It can take negative values, and is constrained by the upper and lower aFRR capacity limits, as given by Eqs. 3.4 and 3.5. The $\overline{x}$ and $\underline{x}$ limits are set at 300 MW and -300 MW, respectively.

$$x_t \leq \overline{x} \quad \forall t \tag{3.4}$$

$$x_t \geq \underline{x} \quad \forall t \tag{3.5}$$

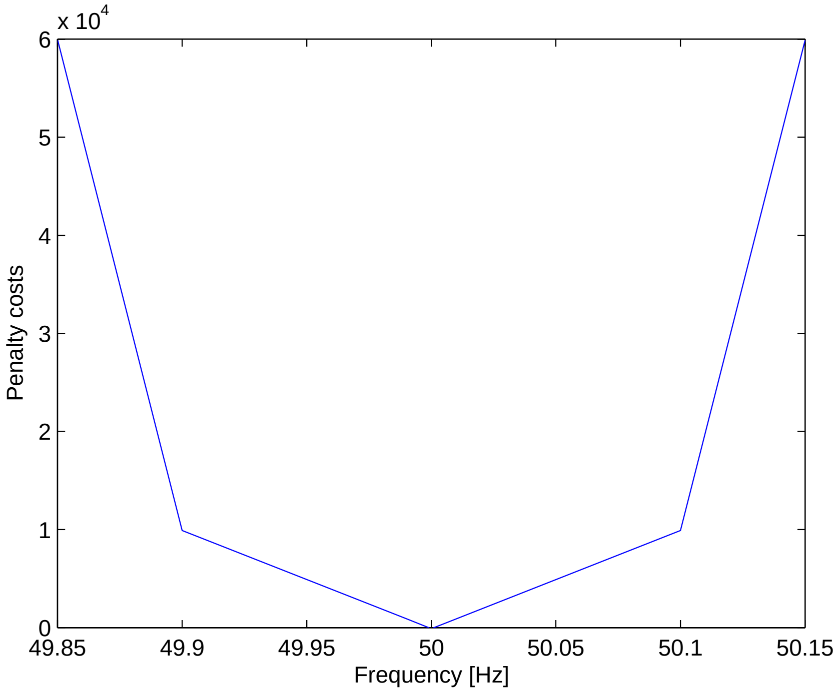


Figure 3.1: Penalty costs imposed on objective function for different frequency deviations

The $x_t$ term is not included in the objective function, meaning from a model perspective there is no associated cost with activating aFRR. Therefore, the model will use the aFRR as a free resource if necessary. This has an impact on the results, and is discussed in 5.2.3.

### 3.2.3 Frequency Deviation Calculations

As mentioned, frequency deviations are handled using penalty functions rather than linear constraints in order to ensure convergence of the optimization problems for challenging imbalance scenarios. The penalty cost function is a piecewise linearised function, imposing larger costs on deviations outside a given range.

The estimated system frequency is calculated directly from the difference of the forecasted imbalance $\omega_t$ and the sum of activated power reserves as shown in Eq. (3.6). The reserves activation includes the participation from aFRR. The calculation uses the frequency bias factor $\lambda$, which is a simplification, as will be discussed in Section 5.2.4. Its value is chosen to be 7000 MW, which is roughly equivalent to the frequency bias in the Nordic system close to the nominal frequency.

Furthermore, the system frequency deviation is calculated for each time step as the sum of two components, given by Eqs. (3.9) and (3.10) for positive and negative deviations, respectively. The $\epsilon$ parameter describes a the size of the dead band around the nominal frequency for which no penalty cost incurs.

The two different variables ($f_t^{o1}$ and $f_t^{o2}$ for positive deviations, $f_t^{u1}$ and $f_t^{u2}$ for negative deviations) are related to the different pieces $k \in 1, 2$ of the piecewise linearised penalty function in Eq. (3.3). Thus, the least expensive variables are constrained to

Table 3.1: The parameters used for frequency deviation calculation and penalties

| Parameter | Value |
|---|---|
| $\lambda$ | 7000 MW |
| $f_U$ | 50.1 Hz |
| $f_L$ | 49.9 Hz |
| $\epsilon$ | 0.001 Hz |
| $p_1$ | 100 000 €/Hz |
| $p_2$ | 1 000 000 €/Hz |

the fixed breakpoint values in Eqs. (3.7) and (3.8). Frequency deviations outside these limits increase the second set of deviation variables, which have higher marginal costs. The resulting penalty cost characteristic with break points and a (small) dead band is shown in Figure 3.1. Finally, Equation (3.11) states the non-negativity of all frequency deviation variables.

$$f_t - \frac{1}{\lambda}\sum_{t\in T}(\sum_{b\in B_u} y_{b,t} - \sum_{b\in B_d} y_{b,t} + x_t + \omega_t) = f_N \qquad \forall t \tag{3.6}$$

$$f_t^{o1} \leq f_U - f_N - \epsilon \quad \forall t \tag{3.7}$$

$$f_t^{u1} \leq f_N - f_L - \epsilon \quad \forall t \tag{3.8}$$

$$f_t^{o1} + f_t^{o2} \geq f_t - f_N - \epsilon \quad \forall t \tag{3.9}$$

$$f_t^{u1} + f_t^{u2} \geq f_N - f_t - \epsilon \quad \forall t \tag{3.10}$$

$$f_t^{ok}, f_t^{uk} \geq 0 \qquad \forall k, \forall t \tag{3.11}$$

The penalty levels depend on the parameters $\lambda$, $f_U$, $f_L$, $\epsilon$ and the cost terms $p_k$. These have been set to have the values given in Table 3.1. Note that the $p_k$ contain the time scaling factor, meaning the marginal penalty per MWh is a factor $\frac{1}{12}$ lower. This means that for deviations in the order of 100 MW, the marginal frequency deviation penalty will be roughly 4 times as large as a typical marginal bid price for upward regulation. The breakpoint values have been chosen on the basis of the frequency limits for normal operation in Norway [21].

### 3.2.4 Commitment Status and Initialization

Contrary to the model described in [6], the balancing energy activation model uses only a single set of binary variables, $u_{b,t}$. This is motivated by and an improvement in terms of computational efficiency, but at the same time requires block profiles of activated bids, which provides inaccurate frequency deviation estimates, as discussed in 5.2.2. The binary variables indicate the commitment status for each bid and time step. The continuous decision variables $y_{b,t}$ denote the power activated from bid $b$ at time step $t$. For the first time step, both sets of variables are initialized to their current status, as given in a separate data file.

$$u_{b,T^{start}} = IA_b \quad \forall b \tag{3.12}$$
$$y_{b,T^{start}} = IG_b \quad \forall b \tag{3.13}$$

### 3.2.5 Constraints on Capacity and Ramping

The constraint in Eq. (3.14) limits power output from each bid to their maximum capacities, or to zero if the bid is not activated, in which case the commitment variable $u_{b,t} = 0$. The minimum generation constraint in Eq. (3.15) prevents $u_{b,t} = 1$ unless $y_{b,t}$ is above a certain level $\underline{y}_b$, which is chosen to be 1 MW for all bids. The 1 MW limit is given as the minimum bid size from [5]. Using this formulation for maximum and minimum constraints, bids may be modelled as indivisible by setting $\underline{y}_b = \overline{y}_b$.

When activated, bids are assumed to be running a flat profile, i.e. the power will remain constant during the delivery period. This is ensured by constraining maximum ramp rates to be zero when the bid is not starting up or shutting down, as shown in Eqs. (3.16) and (3.17)[1]. In traditional unit commitment models with longer time steps, scheduled power is usually allowed to change between time steps. Removing the ramp rate constraints will allow infinite ramp rates between periods, while the solution proposed by [48] enables using different ramp rates during start-up and normal operation. For the Fluid Profile scenarios (cf. Section 3.8.2), the ramp rate restrictions are simply disregarded.

$$y_{b,t} \le \overline{y}_b u_{b,t} \qquad \forall b, \forall t \tag{3.14}$$
$$y_{b,t} \ge \underline{y}_b u_{b,t} \qquad \forall b, \forall t \tag{3.15}$$
$$y_{b,t} \le y_{b,t-1} + \overline{y}_b (u_{b,t} - u_{b,t-1}) \quad \forall b, \forall t \tag{3.16}$$
$$y_{b,t} \ge y_{b,t-1} - \overline{y}_b (u_{b,t-1} - u_{b,t}) \quad \forall b, t > T^{start} \tag{3.17}$$

The unit commitment formulation used gives a *block bid* behaviour in that bids are either activated or deactivated. This is a simplification which influences the model behaviour and results, and will be discussed in Section 5.2.2. In short, the power activation schedules given by the model have a rectangular shape, while in reality, power is also delivered during ramping in the activation and deactivation periods.

From the Standard Product definitions, there are requirements on bid activation and deactivation time. This is implemented by imposing a delay on the activation of a bid by constraining its unit commitment variable for the corresponding amount of time steps, as shown in Eq. (3.18). When bids are deactivated, a similar constraint (Eq. 3.19) prevents activation until after a downtime equivalent to the deactivation and activation period of the product. The $M$ and $m$ coefficients are chosen to be 10 and 0.1, respectively.

[1]The formulations of the maximum ramp rate constraints have been found to be erroneous, as they do not allow partial bid activation. This is discussed in Section 5.3.3.

$$u_{b,t} = 0 \qquad \forall b, t \in \{1, ..., \frac{PP_p}{LT}\} \tag{3.18}$$

$$u_{b,t} \leq M u_{b,t-1} + 1 - m \sum_{i \in [\frac{FAT_p + DT_p}{LT}]} u_{b,t-i} \quad \forall b, t > T^{start} + [\frac{FAT_p + DT_p}{LT}] \tag{3.19}$$

### 3.2.6 Constraints on Bid Duration

Activated bids must run nominally for at least the minimum delivery period (as specified in the Standard Product definitions). For the minimum duration constraints in Eq. (3.21), (3.22), and (3.23), a linearisation based on [49] was used. For re-dispatch optimizations, these constraints are coupled to sunk commitment decisions using the calculated *minimum remaining duration* variable $L_b$, as shown in Eq. 3.20 The maximum duration constraint is given in Eq. (3.24). For all bids, the maximum duration period $\overline{DP}_b$ is given in the bid list, and has been set to 120 minutes.

$$L_b = \min\left\{|T| - T^{start}, (\underline{DP}_p - U_{b,T^{start}-1}) u_{b,T^{start}-1}\right\} \quad \forall b \tag{3.20}$$

$$\sum_{t=T^{start}}^{T^{start}+L_b} u_{b,t} = L_b \qquad \forall b \tag{3.21}$$

$$\sum_{t=s}^{s+[\frac{DP_p}{LT}]-1} u_{b,t} \geq \left[\frac{DP_p}{LT}\right](u_{b,s} - u_{b,s-1}) \quad \forall b, s \in \{T^{start} + L_b + 1, ..., |T| - \left[\frac{DP_p}{LT}\right] + 1\} \tag{3.22}$$

$$\sum_{t=s}^{|T|} u_{b,t} \geq \sum_{t=s}^{|T|} (u_{b,s} - u_{b,s-1}) \qquad \forall b, s \in \{|T| - \left[\frac{DP_p}{LT}\right] + 2, ..., |T|\} \tag{3.23}$$

$$\sum_{t \in T} v_{b,t} \leq \overline{DP}_b \qquad \forall b \tag{3.24}$$

### 3.2.7 Binary Requirements

All unit commitment variables are required to take binary variables only, as expressed in Eq. (3.25). All other decision variables are considered continuous and non-negative, apart from the aFRR activation variables $x_t$, which can take negative values.

$$u_{b,t} \in \{0, 1\} \quad \forall b, \forall t \tag{3.25}$$

### 3.2.8 Scenario Specific Constraints

While most of the scenario specificities are given through the input data files, some of the different Afternoon Scenarios described in Section 3.8.2, require additional or alternative constraint formulations.

The constraints in Eq. 3.26 and 3.27 are used for bids marked as unavailable in the bid list to fix their commitment statues before or after the hour shift, respectively. These are used to remove all P5 bids from selection for the No P5 scenarios. They are also used for the Some Bids Unav. scenario to hold some bids unavailable before the relevant hour shift.

$$u_{b,t} \leq 0 \quad \forall b, t < T^{HS} \tag{3.26}$$

$$u_{b,t} \leq 0 \quad \forall b, t > T^{HS} + 1 \tag{3.27}$$

For the Fluid Profile scenarios, the ramp rate constraints in Eqs. 3.16 and 3.17 were removed. This in principle enables infinite ramp rates between periods, which is a simplification.

For the Fewer Instr. scenarios, an additional set of decision variables $v_{b,t}$ indicates whether bid $b$ is activated at time $t$. This is used to count and constrain the total amount of activation instructions, as shown in Eq. 3.28. Constraints in Eqs. 3.29, 3.30 and 3.31 are needed to make the $v_{b,t}$ variables give a tight count of activations.

$$\sum_B \sum_T v_{b,t} \leq MI \tag{3.28}$$

$$v_{b,t} \geq u_{b,t} - u_{b,t-1} \quad \forall b, t > T^{start} \tag{3.29}$$

$$v_{b,t} \leq u_{b,t} \quad \forall b, \forall t \tag{3.30}$$

$$v_{b,t} \leq 1 - u_{b,t-1} \quad \forall b, t > T^{start} \tag{3.31}$$

## 3.3 Notation

### Sets and indices

| | |
|---|---|
| $p \in P$ | Product types |
| $b \in B_d$ | Balancing power bids for downward regulation |
| $b \in B_u$ | Balancing power bids for upward regulation |
| $B = \{B_d, B_u\}$ | Set of all upwards and downwards bids |
| $t \in T$ | Time steps in the scheduling horizon |
| $s \in T$ | Secondary index used for time steps in the scheduling horizon |
| $k \in K$ | Linear pieces of penalty cost curve |

### Parameters

| | |
|---|---|
| $c_b$ | Bid cost in €/MWh |
| $DT_p$ | Maximum deactivation time of product $p$ |
| $\overline{DP_b}$ | Maximum delivery period of bid $b$ |

| | |
|---|---|
| $\underline{DP_p}$ | Minimum delivery period of product $p$ |
| $\epsilon$ | Frequency deviation dead band |
| $FAT_p$ | Full activation time of product $p$ |
| $f_L$ | Lower split limit on frequency deviation penalty |
| $f_N$ | Nominal system frequency |
| $f_U$ | Upper split limit on frequency deviation penalty |
| $IA_b$ | Initial activation status of bid $b$ |
| $IG_b$ | Initial generation status of bid $b$ |
| $\lambda$ | Frequency bias of the area |
| $L_b$ | Calculated minimum remaining duration for bid $b$ |
| $LT$ | Length of time steps in minutes |
| $m$ | Sufficiently small coefficient |
| $M$ | Sufficiently large coefficient |
| $MI$ | Maximum amount of activation instructions |
| $p^{spot}$ | Spot market electricity price |
| $p_k$ | Marginal penalty cost on piece $k$ |
| $T^{HS}$ | Time step for Hour Shift |
| $T^{start}$ | Time step at start of optimization window |
| $U_{b,t}$ | Number of time steps bid $b$ has been continuously on at end of time $t$ |
| $\overline{y}_b$ | Maximum generation capacity from bid $b$ |
| $\underline{y}_b$ | Minimum generation capacity from bid $b$ |
| $\overline{x}$ | Upper aFRR capacity limit |
| $\underline{x}$ | Lower aFRR capacity limit |
| $\omega_t$ | Forecasted imbalance in MW at time $t$ |

### Variables

| | |
|---|---|
| ${f_t}^{ok}$ | Positive frequency deviation at time $t$ for linear penalty piece $k$ |
| ${f_t}^{uk}$ | Negative frequency deviation at time $t$ for linear penalty piece $k$ |
| $u_{b,t}$ | Binary variable indicating commitment status, i.e. whether bid $b$ is activated at time step $t$ |
| $v_{b,t}$ | Variable indicating whether bid $b$ is started up at time $t$. |
| $x_t$ | Power activated from aFRR at time $t$ |
| $y_{b,t}$ | Power activated from bid $b$ at time $t$ |

## 3.4 Model Implementation

The mathematical model was implemented in Xpress-Mosel [50]. The standard form of the model implementation is included in Appendix A. This model contains the objective functions and constraints, as described in Section 3.2, in addition to scenario initialization and results management scripts. The imbalance forecasts, Standard Product definitions and bid list is obtained from an external input file using the Excel format, allowing the same model to be used for the different scenarios. Model parameters, such as frequency bias and penalty cost levels are defined within the model.

The running time of the model depends on the input data and model parameters. For the scenarios used in this report, running times vary from a few seconds, up to several hours in some cases. The running time has been found to be sensitive to penalty cost levels and imbalance volumes. Compared to [6], the input data dimensions used are larger, while the relative amount of binary variables is reduced.

## 3.5 Imbalance Forecasts

The optimization model uses an imbalance forecast to schedule activation of reserves. The imbalance forecasts used in the scenarios, as described in 3.8, are all derived from an imbalance profile calculated by Bjørn Bakken [51] for a given day in 2014 for the Norwegian power system. It is calculated using a approach very similar to the one described in Eq. 2.1 in Section 2.2.4, i.e. using forecasts and schedules for consumption, generation and export.

The resulting imbalance profile is shown in Figure 3.2. The calculated profile has a granularity of 5 minutes. Most of the underlying forecasts, however, use longer time steps. In these cases, linear interpolation has been used to estimate the forecast values for each 5 minute step [51]. More specifically;

- Consumption forecast: linearization of quarterly values
- Generation schedules: hourly schedules adjusted around hour shift (+/- 5 min)
- AC exhange: linearization of hourly values (+/- 30 min)
- HVDC exchange: break point values with 5 min resolution are used

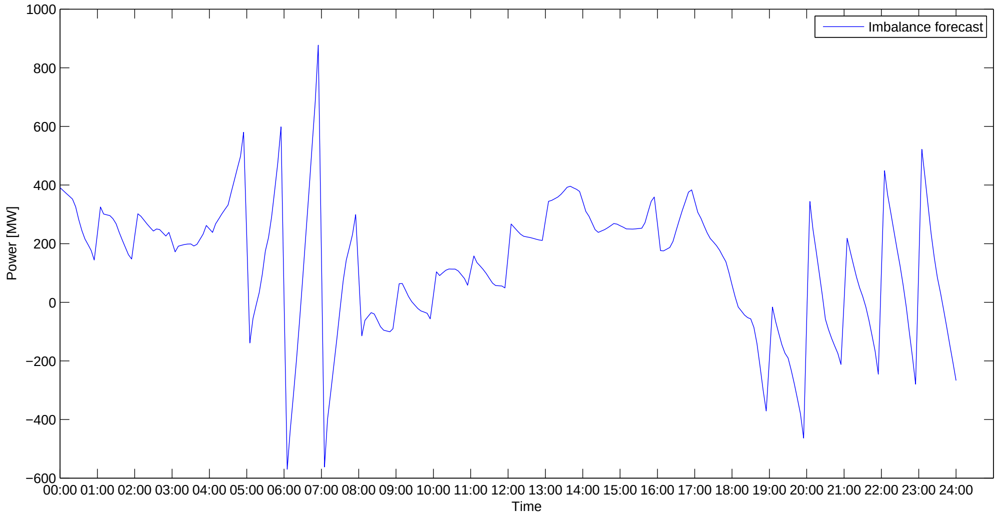


Figure 3.2: Imbalance forecast calculated for 4 February 2014.

### 3.5.1 Structural Imbalances

The large imbalances occuring during the morning and evening hours in the imbalance forecast in Figure 3.2 are examples of of structural imbalances (as described in Section 2.2.2. Figure 3.3 gives a closer view of the forecasted morning imbalances.

These are deterministic imbalances, i.e. they are to a large extent known in advance. Still, in Norway they have traditionally been handled during during real-time operation using short-term manual techniques such as schedule shifting and mFRR. The introduction of schedule smoothing, as described in 3.5.2 enables schedule adjustments hours in advance to cover most of these imbalances without real-time activation of reserves.

### 3.5.2 Generation Schedule Smoothing Algorithm

The generation schedule smoothing algorithm was introduced in Section 2.4.7. In this section, the main principles of the algorithm will be explained. The algorithm will also be employed to the forecasted structural imbalances described in Section 3.5.1. The resulting smoothed forecast is shown in Figure 3.4.

The generation schedule smoothing algorithm is applied the day before and uses an imbalance forecast for the next day. For each hour, the algorithm decides on whether generation schedules need to be adjusted. Adjustment decisions are data driven, and are made separately for smoothing before and after the hour shift using the steps shown in Table 3.2. Note that the notation used differs from the one used in the balancing energy activation model.

Essential to decisions are the value for the forecasted imbalance $\Delta\hat{P}_{H-t}$ at time $t$ from the given hour shift, e.g. $\Delta\hat{P}_{H-5}$ is the forecasted imbalance 5 minutes before hour shift $H$, and $P^{ss}_{H-t}$ denotes the amount of power in MW that should be shifted to time $t$ before hour shift $H$. When decisions on smoothing have been made, the algorithm uses generation schedules to determine which units to suggest for schedule adjustments. Units

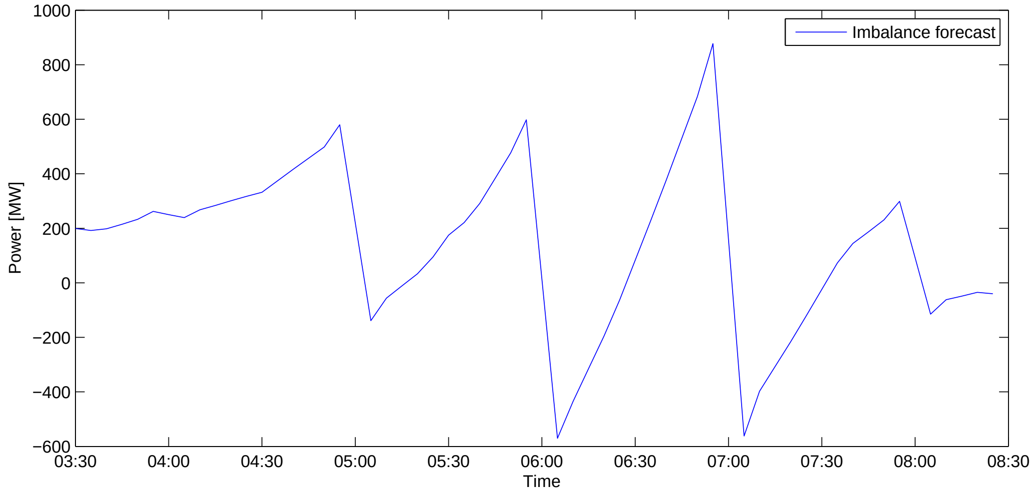


Figure 3.3: Imbalance forecast of the morning structural imbalances for 4 February 2014.

Table 3.2: The steps used by the generation schedule smoothing algorithm, applied for a pre-hour shift calculation.

| **Step** | **Purpose** | **Action** |
|---|---|---|
| 1 | Determine need for smoothing | If $\lvert\Delta\hat{P}_{H-5}\rvert > 450$ MW: make 15 min shifts. If $> 600$ MW: make 30 min shifts as well |
| 2 | Calculate 30 min shift (if any) | $P^{ss}_{H-30} = \Delta\hat{P}_{H-25}$ |
| 3 | Calculate 15 min shift (if any) | $P^{ss}_{H-15} = \Delta\hat{P}_{H-10} - P^{ss}_{H-30}$ |

are chosen to participate in the order of increasing marginal cost, apart from in the case where the scheduled generation increase is larger than what is needed, in which case they are skipped on the list [27].

## 3.6 Standard Product Definitions

The set of Standard Product definitions used is a subset of the definitions proposed in Table 2.2. More specifically, products P1, P2, P4 and P5 are used. Products P6, P7 and P8 use scheduled activation, i.e. there are restrictions on which moments in time they may be activated. In activation time and delivery period they are comparable to P1. They are excluded for the purpose of reducing complexity in analysis. The definition of P3 is very flexible, originally intended to be able to fit the behaviour of the BOA product, as used in the UK. It is left out due to its minimum delivery period being shorter than the granularity of the optimization model. The proposed aFRR Standard Products from

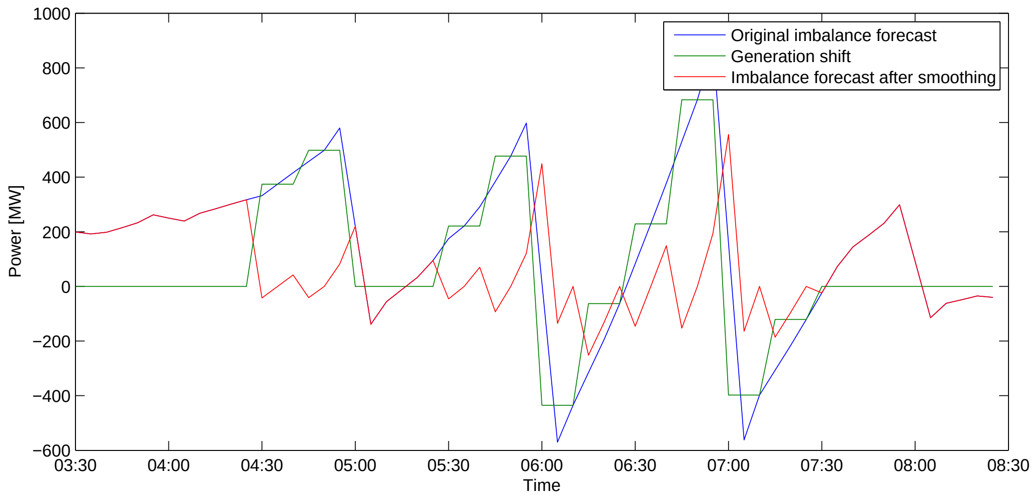


Figure 3.4: Schedule smoothing applied to an imbalance forecast.

Table 2.1 are not used.

## 3.7 Balancing Activation Market

As mentioned, the task of the Balancing Energy Activation Model is to schedule an activation of balancing energy that results in minimum total cost. This implies finding the optimal schedule for each of the bids available in the mFRR activation market. A fictional list of bids has been created to resemble the mFRR bids available for upward and downward regulation. The lists for upward and downward regulation are shown in Tables 3.3 and 3.4, respectively. These tables show the individual bids with their associated prices, maximum capacity limits, and product types. In addition, the list contains information on availability for different parts of the scheduling horizon.

The bid list contains 50 bids in total, resulting in total available volumes as shown in Table 3.5 and an average bid size of 74 MW. In the real RPM, the average size is lower, but the number of bids is higher. The bids in the fictive lists have been distributed among the different Standard Products, resulting in 12 or 13 bids available for each product. This amount of bids is considered sufficiently large to allow abundant alternatives for scheduling.

Bids are been assumed available with constant prices and capacities for the entire window of optimization. The spot price *pspot* has also been assumed constant at a level of 33.0 €/MWh for the entire window. This simplification will be discussed in Section 5.2.7.

Fig. 3.5 shows the available mFRR capacity from each of the products, sorted in the merit order. Fig. 3.6 shows the merit order curve for the aggregated list of bids. As can be seen from 3.5, the least expensive bids for upward regulation are P5 bids, while P2 bids start out at a higher price level. Similarly, P4 bids for downward regulation start out at a low price level. This bias in price levels influences results, and is discussed in Section 5.2.7.

Table 3.3: The bid list used by the model for downward regulation. All data are fictional.

| **No.** | **Bid name** | **Max size** [MW] | **Bid price** [€/MWh] | **Product type** |
|---|---|---|---|---|
| 1 | Haugesund | 68 | 18.1 | P5 |
| 2 | Harstad | 77 | 21.9 | P4 |
| 3 | Larvik | 99 | 23.6 | P4 |
| 4 | Tønsberg | 59 | 24.4 | P2 |
| 5 | Molde | 72 | 24.7 | P4 |
| 6 | Uppsala | 51 | 25.4 | P2 |
| 7 | Stockholm | 89 | 26.1 | P5 |
| 8 | Porsgrunn | 130 | 26.6 | P2 |
| 9 | Bodø | 55 | 26.7 | P4 |
| 10 | Oslo | 38 | 27.5 | P4 |
| 11 | Horten | 68 | 27.9 | P1 |
| 12 | Trondheim | 73 | 28.2 | P5 |
| 13 | Göteborg | 83 | 28.9 | P1 |
| 14 | Ålesund | 45 | 29.4 | P2 |
| 15 | Drammen | 71 | 29.6 | P1 |
| 16 | Linköping | 109 | 29.8 | P2 |
| 17 | Gjøvik | 85 | 31.4 | P1 |
| 18 | Västerås | 22 | 31.7 | P1 |
| 19 | Askøy | 60 | 32.1 | P2 |
| 20 | Malmö | 83 | 32.2 | P1 |
| 21 | Örebro | 63 | 32.4 | P5 |

Table 3.4: The bid list used by the model for upward regulation. All data are fictional.

| No. | Bid name | Max size [MW] | Bid price [€/MWh] | Product type |
|---|---|---|---|---|
| 22 | Lillehammer | 95 | 33.4 | P5 |
| 23 | Fredrikstad | 39 | 34.5 | P5 |
| 24 | Moss | 78 | 35.8 | P1 |
| 25 | Helsingborg | 140 | 35.9 | P4 |
| 26 | Tromsø | 36 | 36.4 | P1 |
| 27 | Kristiansand | 145 | 36.9 | P5 |
| 28 | Mo i Rana | 102 | 37 | P5 |
| 29 | Jönköping | 114 | 37.3 | P5 |
| 30 | Stavanger | 91 | 37.8 | P4 |
| 31 | Norrköping | 41 | 38 | P4 |
| 32 | Kristiansund | 27 | 38.7 | P1 |
| 33 | Korsvik | 30 | 38.9 | P1 |
| 34 | Bergen | 114 | 39.2 | P4 |
| 35 | Tromsdalen | 111 | 39.4 | P5 |
| 36 | Jessheim | 81 | 39.8 | P4 |
| 37 | Hønefoss | 49 | 40.1 | P2 |
| 38 | Lund | 23 | 40.3 | P2 |
| 39 | Umeå | 122 | 40.8 | P1 |
| 40 | Ski | 33 | 41.5 | P2 |
| 41 | Sandefjord | 60 | 42.1 | P1 |
| 42 | Gävle | 29 | 42.2 | P5 |
| 43 | Kongsberg | 89 | 42.6 | P2 |
| 44 | Borås | 31 | 42.9 | P4 |
| 45 | Alta | 57 | 43.6 | P2 |
| 46 | Elverum | 77 | 44 | P1 |
| 47 | Arendal | 145 | 44.3 | P2 |
| 48 | Hamar | 103 | 47.1 | P4 |
| 49 | Halden | 79 | 47.8 | P2 |
| 50 | Narvik | 59 | 51.2 | P5 |

Table 3.5: The total amount of available aFRR and mFRR from the fictional bid lists in Tables 3.3 and 3.4.

| Reserve type | Upward capacity [MW] | Downward capacity [MW] |
|---|---|---|
| aFRR | 300 | 300 |
| mFRR | 2200 | 1500 |

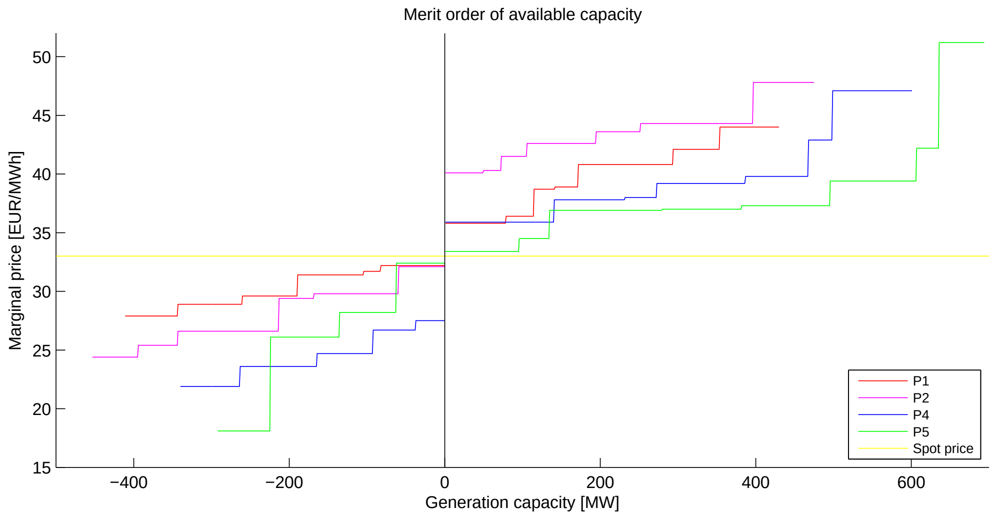


Figure 3.5: Merit order curves for the different Standard Product mFRR bid instances

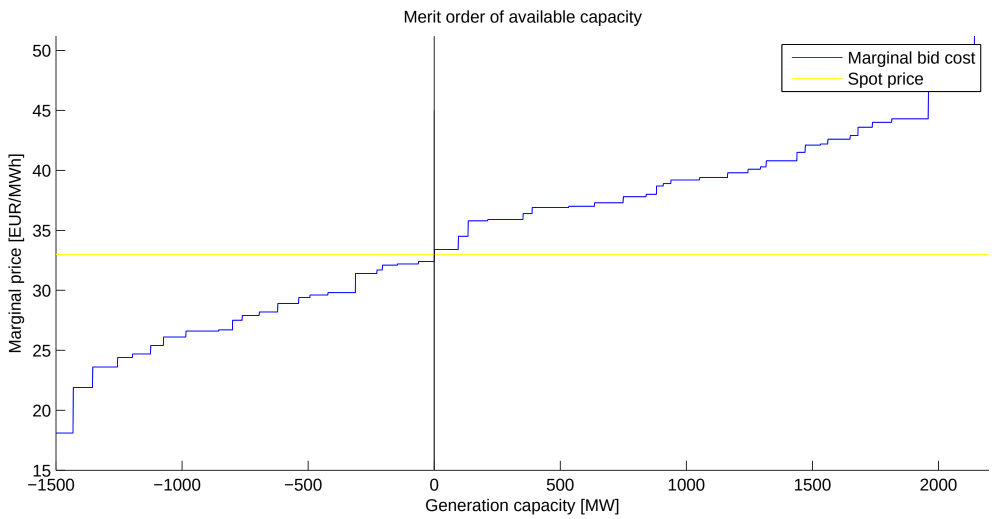


Figure 3.6: Aggregated merit order curve for all available mFRR bid instances

Table 3.6: The four scenarios included in the Morning Scenarios category

| **Modification** | **Operation as expected** | **Unexpected generator outage** |
|---|---|---|
| **No schedule smoothing** | Morning Base Case | Morning Generator Outage |
| **Schedule smoothing employed** | Morning Schedule Smoothing | Morning Schedule Smoothing Generator Outage |

## 3.8 Scenario Descriptions

A set of different scenarios are created to illustrate and investigate the behaviour of the Balancing Energy Activation Model and the Standard Products for electricity balancing. All of these scenarios are run for a horizon of five hours using 5 minute timesteps. All imbalance forecasts are derived from the imbalance forecast given for Norway, 4 February 2014 (cf. 3.5 [51], although modified in some cases. They also share the set of Standard Product definitions, as described in Section 3.6. The market data is in all cases given by the lists of available bids and their individual properties, as stated in Section 3.7.

However, as not all scenario results are directly comparable to each other, the scenarios are divided by the time of day into two different categories; *morning scenarios* and *afternoon scenarios*.

### 3.8.1 Morning Scenarios

Four scenarios are included in the morning scenarios category. These are related in that they all share the same time window of optimization, i.e. from 03:30 to 08:30 in the morning. This time of day is of special interest due to the occurrence of large structural imbalances. An imbalance forecast for this time window is shown in Figure 3.3.

An important objective of analysis for the morning scenarios category is to investigate the impact of employing schedule smoothing on the activation of balancing energy using Standard Products. This will be done for normal operation, as well as following a large unexpected generator outage. The four morning scenarios are created to resemble these situations, and are showed in Table 3.6.

#### Operation as expected

The term *Operation as expected* is in this context used to denote a situation where the imbalance turns out to be as was forecasted. This is not the same as assuming perfect information, as discussed in Section 5.2.1, but rather a case where the updated forecasts are equal to the original forecast, meaning any re-optimization will give the same dispatch.

#### Unexpected generator outage

The *Unexpected Generator Outage* cases are very similar to the operation as expected cases in that future forecasts generally agree on previous forecasts, thus re-dispatch is

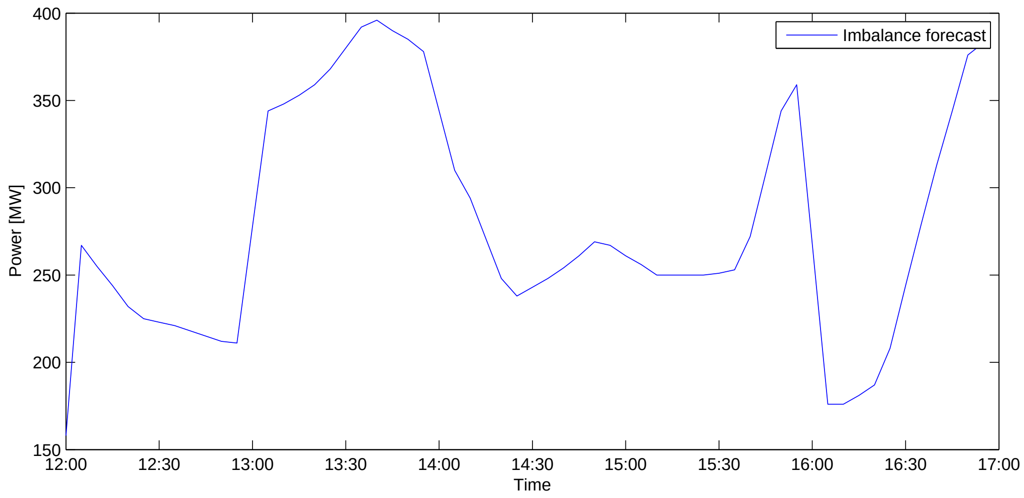


Figure 3.7: Imbalance forecast used in Afternoon Scenarios, calculated for 4 February 2014.

not necessary. This is true with one important exception. At a certain step in time (about 04:45 in the morning), the updated imbalance forecast is suddenly different due to an unexpected generator outage. The imbalance forecast now includes an additional 600 MW which must be covered until 06:00, when the lost generation capacity will be covered using intra-day market trade. Apart from this temporary 600 MW increase, the imbalance forecast is the same.

#### No schedule smoothing

For scenarios with no schedule smoothing, the original, unmodified forecast from Section 3.5, as shown in Figure 3.3 is used for the optimzization. In generator outage scenarios, the lost generation capacity will be superpositioned on this forecast.

#### Schedule smoothing employed

For scenarios with schedule smoothing employed, the original forecast has been modified using the schedule smoothing algorithm described in Section 3.5.2, as shown in Figure 3.4. In generator outage scenarios, the lost generation capacity will be superpositioned on this forecast.

### 3.8.2 Afternoon Scenarios

Ten scenarios are included in the Afternoon scenarios category. These scenarios all share the same time window, i.e. from 12:00 to 17:00. The basic imbalance forecast for this periods is shown in Figure 3.7. For the imbalance forecast used, this is a period of the day with low structural imbalances. The forecasted peak values are sufficiently small not to trigger actions from the schedule smoothing algorithm.

The main emphasis of analysis for the Afternoon scenarios is on constraints in optimization due to Standard Product definitions or operational practices. As for the Morn-

Table 3.7: The six scenarios included in the Afternoon Scenarios category

| Modification | Operation as expected | Unexpected generator outage |
|---|---|---|
| **No changes** | Afternoon Base Case | Afternoon Generator Outage |
| **No P5 available** | Afternoon No P5 | Afternoon No P5 Generator Outage |
| **Some bids unav.** | Afternoon Bids Unav. | Afternoon Bids Unav. Generator Outage |
| **Fluid profile** | Afternoon Fluid Profile | Afternoon Fluid Profile Generator Outage |
| **Fewer instr.** | Afternoon Fewer Instr. | Afternoon Fewer Instr. Generator Outage |

ing Scenarios, the impact of removing or adding constraints will be analysed for both a normal operation and a large generator outage situation. An overview of all Afternoon Scenarios is given in Table 3.7.

### Operation as expected

The term *Operation as expected* is used in the same way as for the Morning Scenarios, resembling a situation where no re-optimization is necessary to follow the imbalance profile.

### Unexpected generator outage

The term *Unexpected generator outage* is used in the same way as for the Morning Scenarios, with the 600 MW outage taking place at about 13:15. The generation capacity will be replaced through the intra-day market from 15:00.

### No changes

*No changes* means no constraints has been added or removed compared to the standard formulation of the model, as presented in Chapter 3.

### No P5 available

*No P5 available* means all bids for the P5 Standard Product has been marked as unavailable in the bid list. These are unavailable for the entire scheduling horizon.

### Some bids unavailable

*Some bids unavailable* means a small subset of the bids have been made unavailable for parts of the time window. More specifically, the seven least expensive bids for upward regulation are unavailable before 14:00. This causes the merit order of bids to change at the 14:00 hour shift.

### Fluid profile

The *Fluid profile* term means bids are not constrained to a flat profile during the delivery period. This resembles an arrangement where the TSO is able to set the power generation level for each activated bid on 5 minute intervals.

### Fewer instructions

The scenario term *Fewer instructions* means that the total amount of activation instructions within the time window is limited. Such a limitation may be regarded as necessary to decrease operational complexity in cases where the optimal schedule suggests an unreasonable amount of activation and deactivation actions. The amount of activations will be limited using a second set of binary variables and a set of constraints.

# Chapter 4

# Results

## 4.1 Morning Scenarios

The optimization model described in Section 3.2 was used for running the Morning scenarios from Section 3.8.1. Some of the important results are presented for the individual scenarios using figures and tables, with the scenarios being ordered as:

1. Morning Base Case
2. Morning Schedule Smoothing
3. Morning Generator Outage
4. Morning Schedule Smoothing Generator Outage

The activation schedules decided by the optimizer are shown in Figures 4.1, 4.2, 4.3, and 4.4 for the individual Morning scenarios. These figures show how and when aFRR and mFRR is dispatched by the optimization model to cover the forecast imbalances. The resulting estimated frequency is also included.

For each of the individual scenarios, Figures 4.5, 4.6, 4.7, and 4.8 show the total activation duration for each of the bids listed in Tables 3.4 and 3.3. Bids are sorted in the order of price, as shown by the blue bid price curve. Bids 1-21 are bids for downward regulation, having prices lower than the spot price (as shown by the green spot price line). Similarly, bids 22-50 are bids for upward regulation, having prices higher than the spot price.

In Table 4.1, some important cost terms are compared for the four morning scenarios, namely the total mFRR activation costs, together with the frequency deviation penalty costs and the shadow price of the aFRR capacity restriction. These are calculated for the full five hour optimization time window.

Table 4.2 presents the total volumes of upward and downward regulation from mFRR and aFRR for each of the individual Morning scenarios. The aFRR saturation column shows the amount of time aFRR activation is at its maximum capacity in either the upward or downward direction. All values are calculated for the full five hour optimization time window.

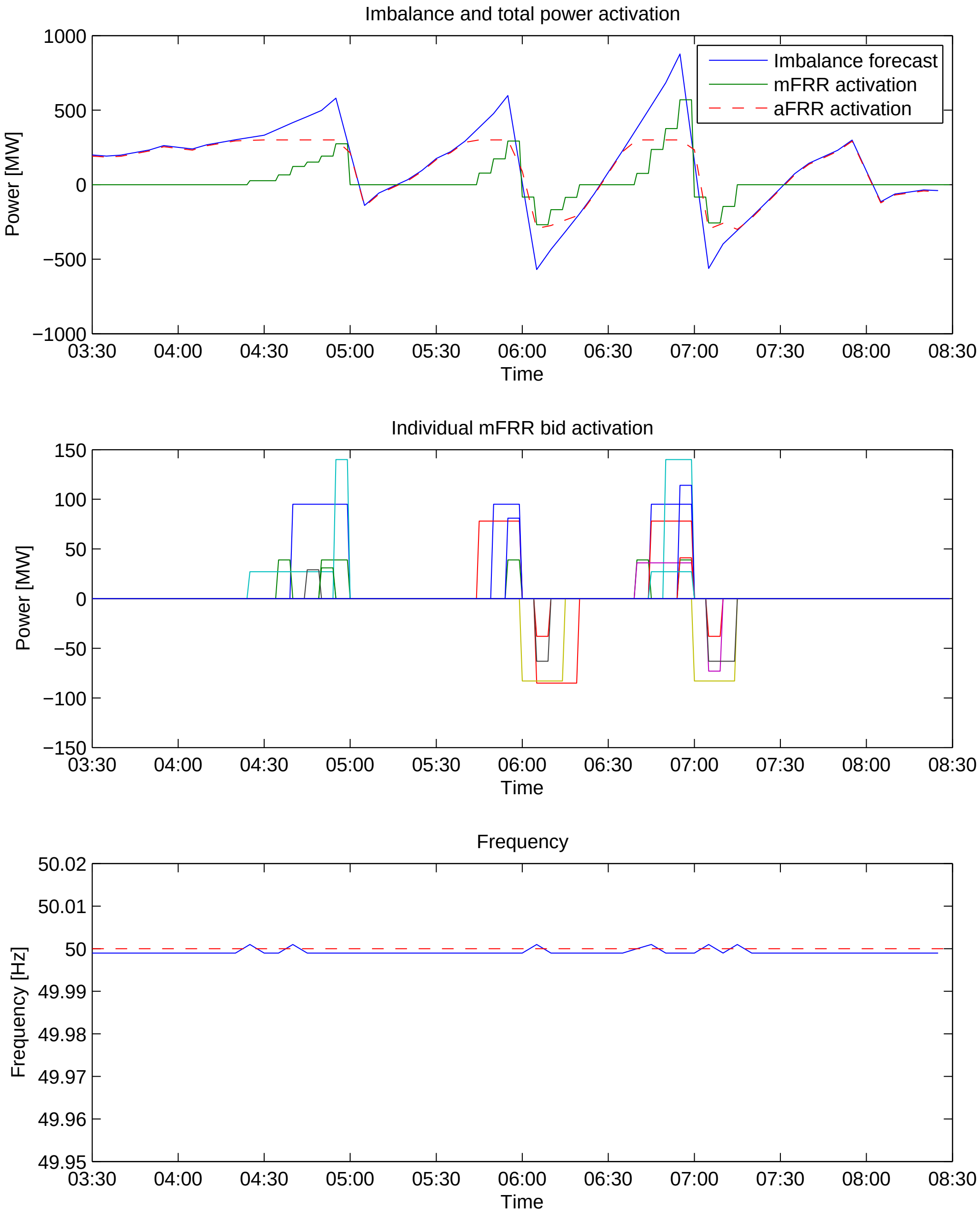


Figure 4.1: Activation of aFRR and mFRR from the Morning Base Case scenario.

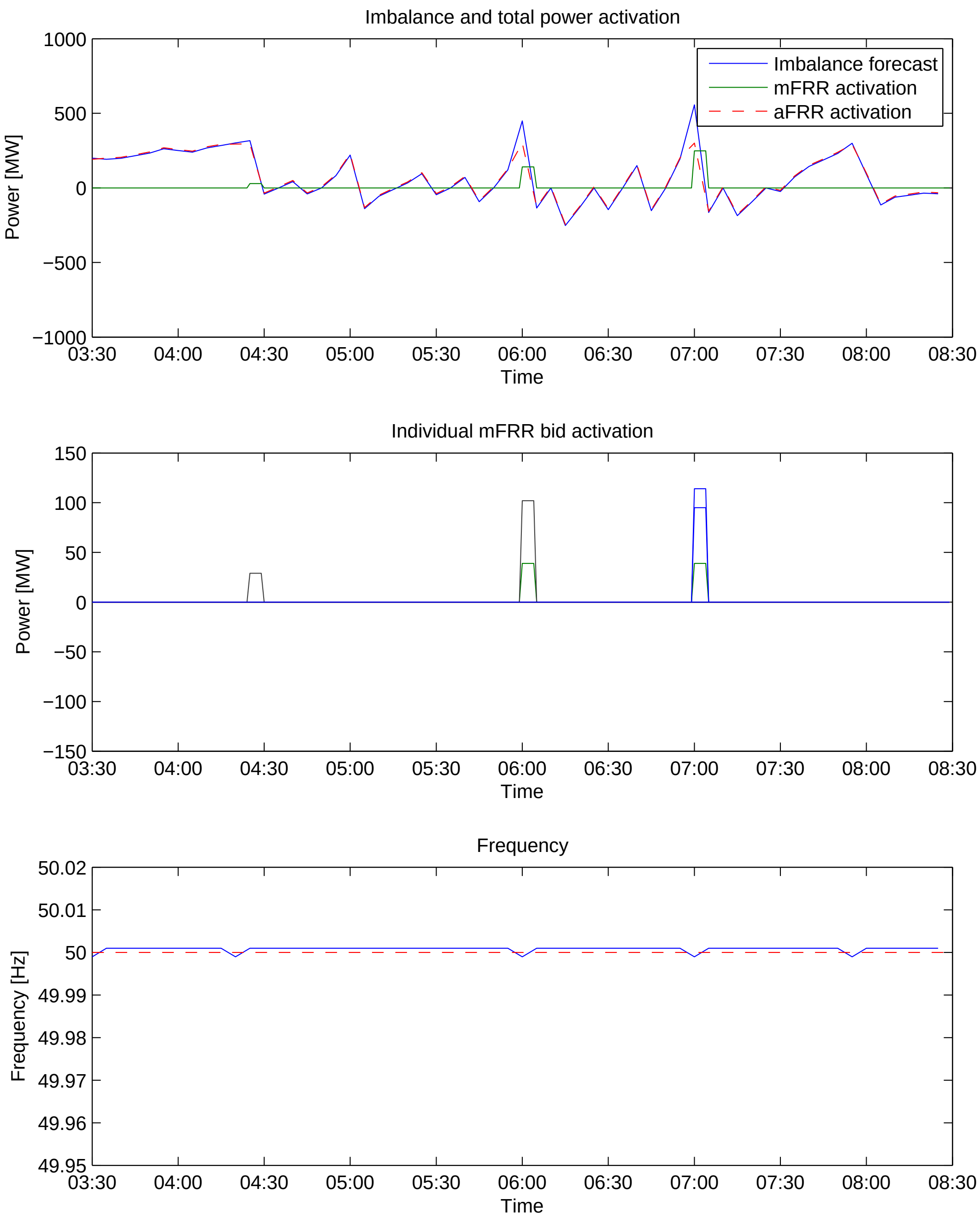


Figure 4.2: Activation of aFRR and mFRR from the Morning Schedule Smoothing scenario.

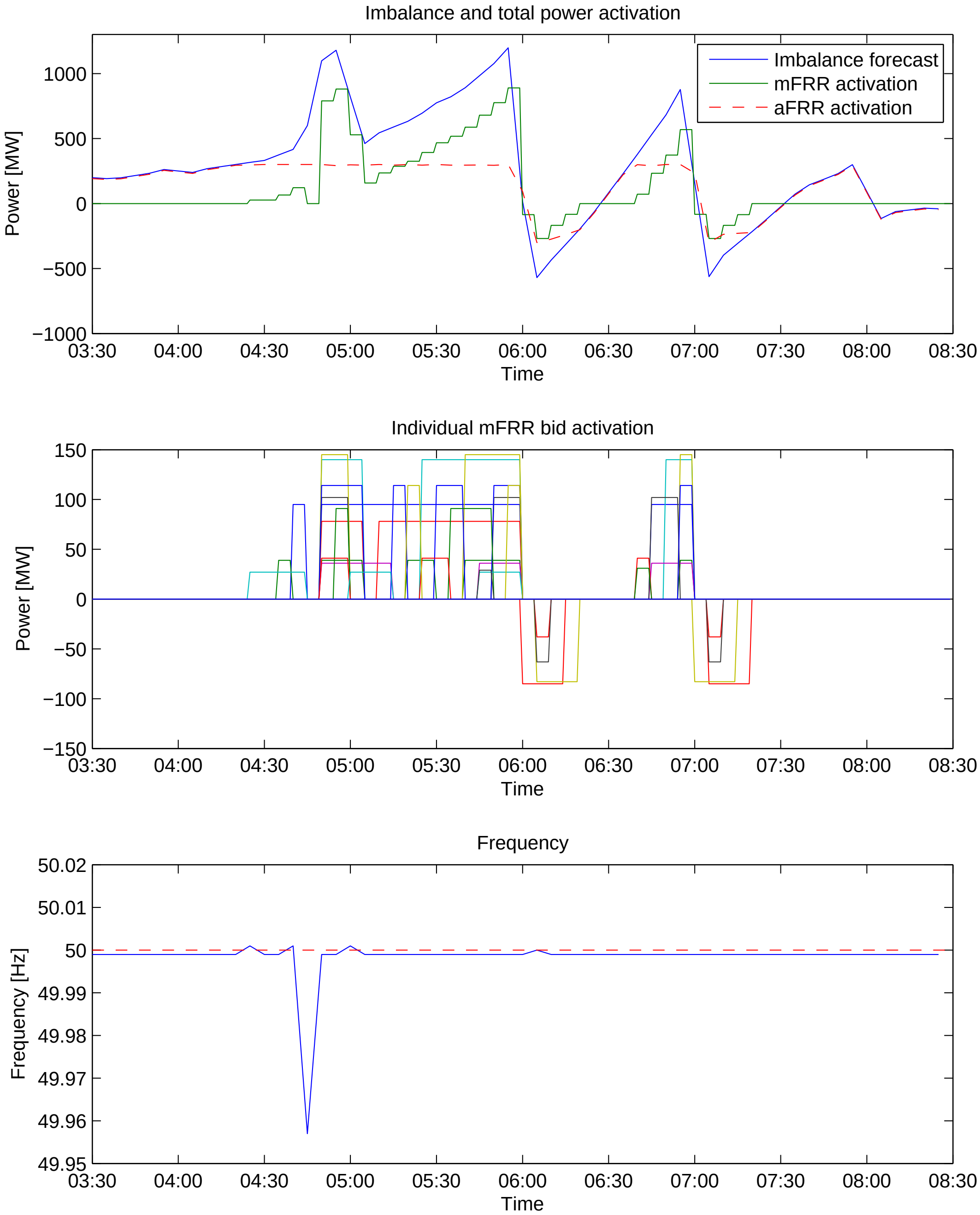


Figure 4.3: Activation of aFRR and mFRR from the Morning Generator Outage scenario.

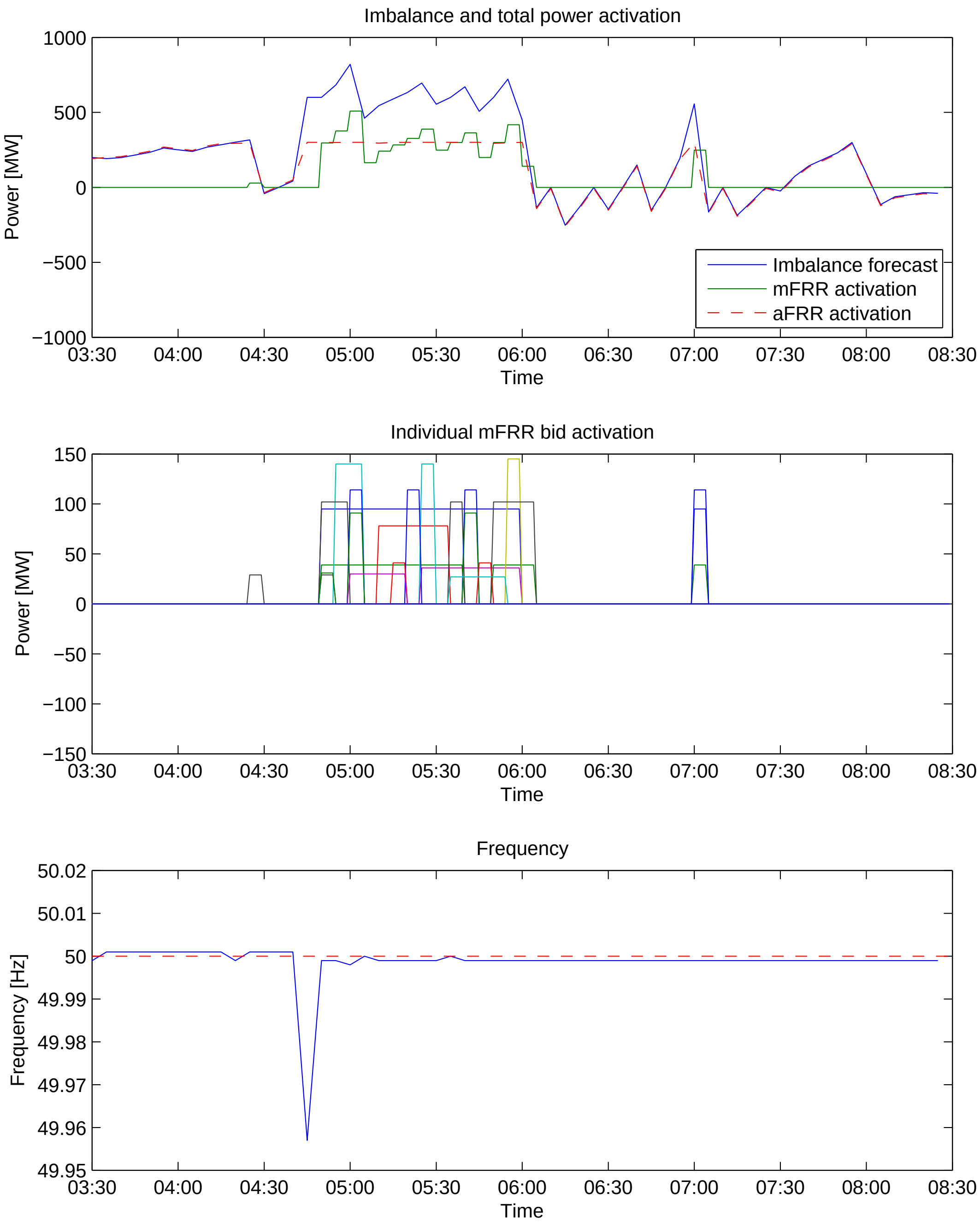


Figure 4.4: Activation of aFRR and mFRR from the Morning Schedule Smoothing Generator Outage scenario.

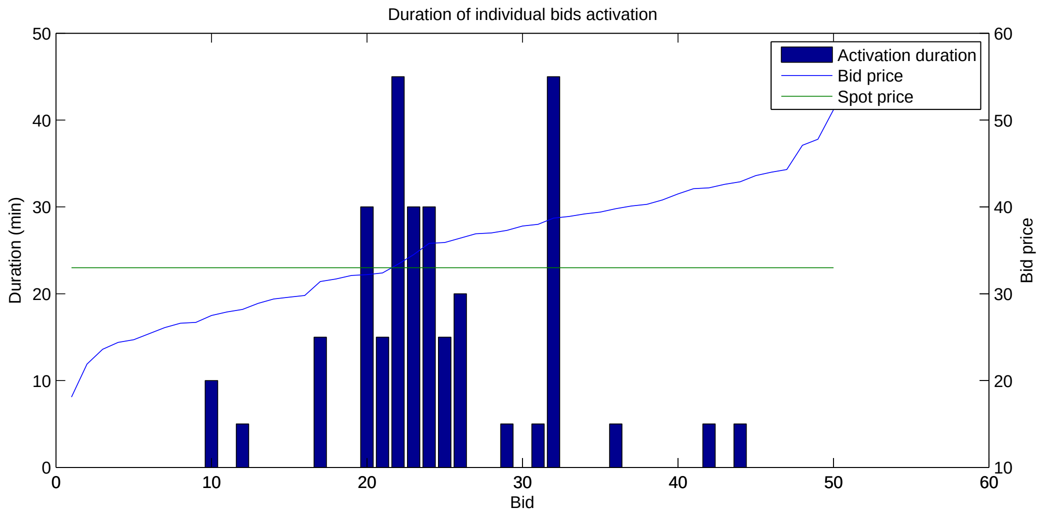


Figure 4.5: Activation duration of individual bids from the Morning Base Case scenario.

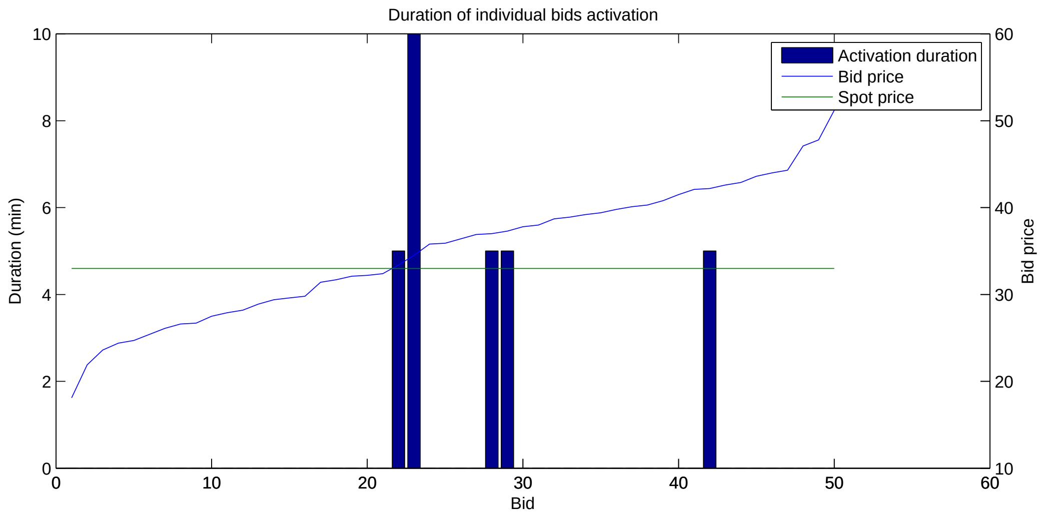


Figure 4.6: Activation duration of individual bids from the Morning Schedule Smoothing scenario.

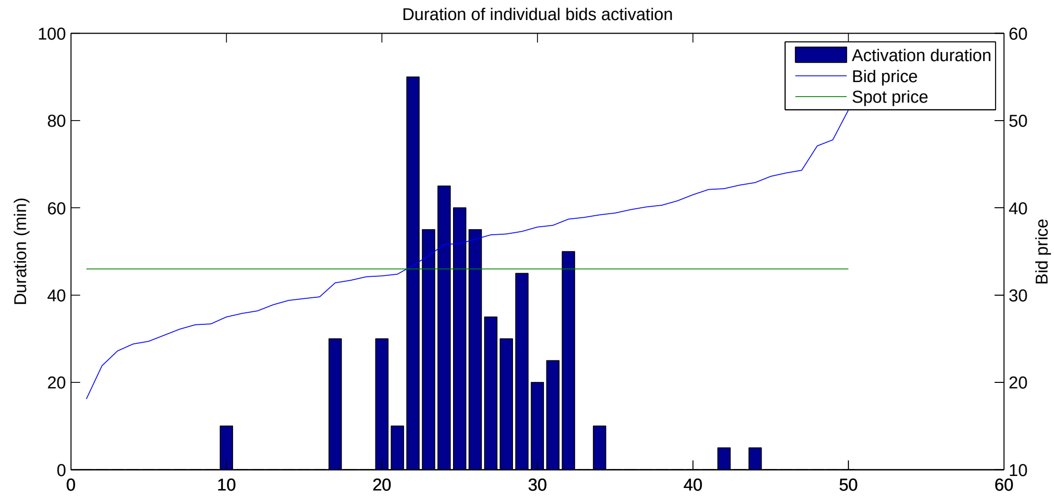


Figure 4.7: Activation duration of individual bids from the Morning Generator Outage scenario.

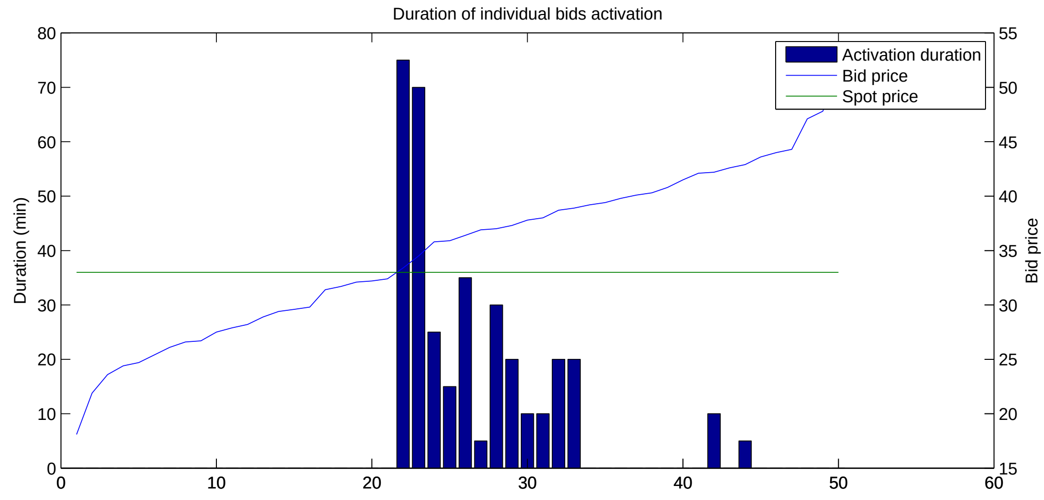


Figure 4.8: Activation duration of individual bids from the Morning Schedule Smoothing Generator Outage scenario.

Table 4.1: Cost results for the different Morning scenarios

| **Scenario** | **mFRR activation cost [€]** | **Freq. dev. penalty cost [€]** | **aFRR cap. shadow price [€/MW]** | **No. of act. marginal value [€]** |
|---|---|---|---|---|
| Morning Base Case | 8 032 | 14 | 50 | 5 |
| Morning Schedule Smoothing | 1 260 | 29 | 29 | 5 |
| Morning Generator Outage | 26 484 | 4 286 | 109 | 7 |
| Morning Schedule Shifting Generator Outage | 14 254 | 4 286 | 142 | 7 |

Table 4.2: Activation volume results for the different Morning scenarios

| **Scenario** | **mFRR volume upwards [MWh]** | **mFRR volume downwards [MWh]** | **aFRR volume upwards [MWh]** | **aFRR volume downwards [MWh]** | **aFRR saturation [% of time]** |
|---|---|---|---|---|---|
| Morning Base Case | 222 | 91 | 780 | 241 | 23 |
| Morning Schedule Smoothing | 34 | 0 | 482 | 156 | 3 |
| Morning Generator Outage | 749 | 91 | 922 | 221 | 38 |
| Morning Schedule Shifting Generator Outage | 402 | 0 | 787 | 147 | 20 |

In Table 4.3, the total activation duration for each product type is given for each of the Morning scenarios, as well as the total mFRR activation duration. Similarly in Table 4.4, the total number of activations for each product type and scenario is presented.

Table 4.3: mFRR activation duration (in minutes) for the different Standard Products and Morning scenarios

| Scenario | P1 | P2 | P4 | P5 | Total |
|---|---|---|---|---|---|
| Morning Base Case | 140 | 0 | 40 | 105 | 285 |
| Morning Schedule Smoothing | 0 | 0 | 0 | 30 | 30 |
| Morning Generator Outage | 230 | 0 | 130 | 270 | 630 |
| Morning Schedule Shifting Generator Outage | 100 | 0 | 40 | 210 | 350 |

Table 4.4: Total number of mFRR actvations for the different Standard Products and Morning scenarios

| Scenario | P1 | P2 | P4 | P5 | Total |
|---|---|---|---|---|---|
| Morning Base Case | 8 | 0 | 7 | 13 | 28 |
| Morning Schedule Smoothing | 0 | 0 | 0 | 6 | 6 |
| Morning Generator Outage | 12 | 0 | 13 | 22 | 47 |
| Morning Schedule Shifting Generator Outage | 4 | 0 | 7 | 15 | 26 |

## 4.2 Afternoon Scenarios

The optimization model described in Section 3.2 was used for running the Afternoon scenarios from Section 3.8.2. Some of the important results are presented for the individual scenarios using figures and tables, with the scenarios being ordered as:

1. Afternoon Base Case
2. Afternoon Generator Outage
3. Afternoon No P5
4. Afternoon No P5 Generator Outage
5. Afternoon Bids Unav.
6. Afternoon Bids Unav. Generator Outage
7. Afternoon Fluid Profile
8. Afternoon Fluid Profile Generator Outage
9. Afternoon Fewer Instr.
10. Afternoon Fewer Instr. Generator Outage

The activation schedules decided by the optimizer are shown in Figures 4.9 to 4.18 for the individual Afternoon scenarios. These figures show how and when aFRR and mFRR are dispatched by the optimization model to cover the forecast imbalances. The resulting estimated frequency is also included.

For each of the individual Afternoon scenarios, Figures 4.19 to 4.28 show the total activation duration for each of the bids listed in Tables 3.4 and 3.3. Bids are sorted in the order of price, as shown by the blue bid price curve. Bids 1-21 are bids for downward regulation, having prices lower than the spot price (as shown by the green spot price line). Similarly, bids 22-50 are bids for upward regulation, having prices higher than the spot price.

For the *Some Bids Unav.* Scenario, bids 22-28 are unavailable before 14:00. Figures 4.29 and 4.30 show the activation duration of individual bids before and after this point in time for the Operation as expected and Generator outage scenarios, respectively.

In Table 4.5, some important cost terms are compared for the four Afternoon scenarios, namely the total mFRR activation costs, together with the frequency deviation penalty costs and the shadow price of the aFRR capacity restriction. These are calculated for the full five hour optimization time window.

Table 4.6 presents the total volumes of upward and downward regulation from mFRR and aFRR for each of the individual Afternoon scenarios. The aFRR saturation column shows the amount of time aFRR activation is at its maximum capacity in either the upward or downward direction. All values are calculated for the full five hour optimization time window.

In Table 4.7, the total activation duration for each product type is given for each of the Afternoon scenarios, as well as the total mFRR activation duration. Similarly, in Table 4.8, the total number of activations for each product type and scenario is presented.

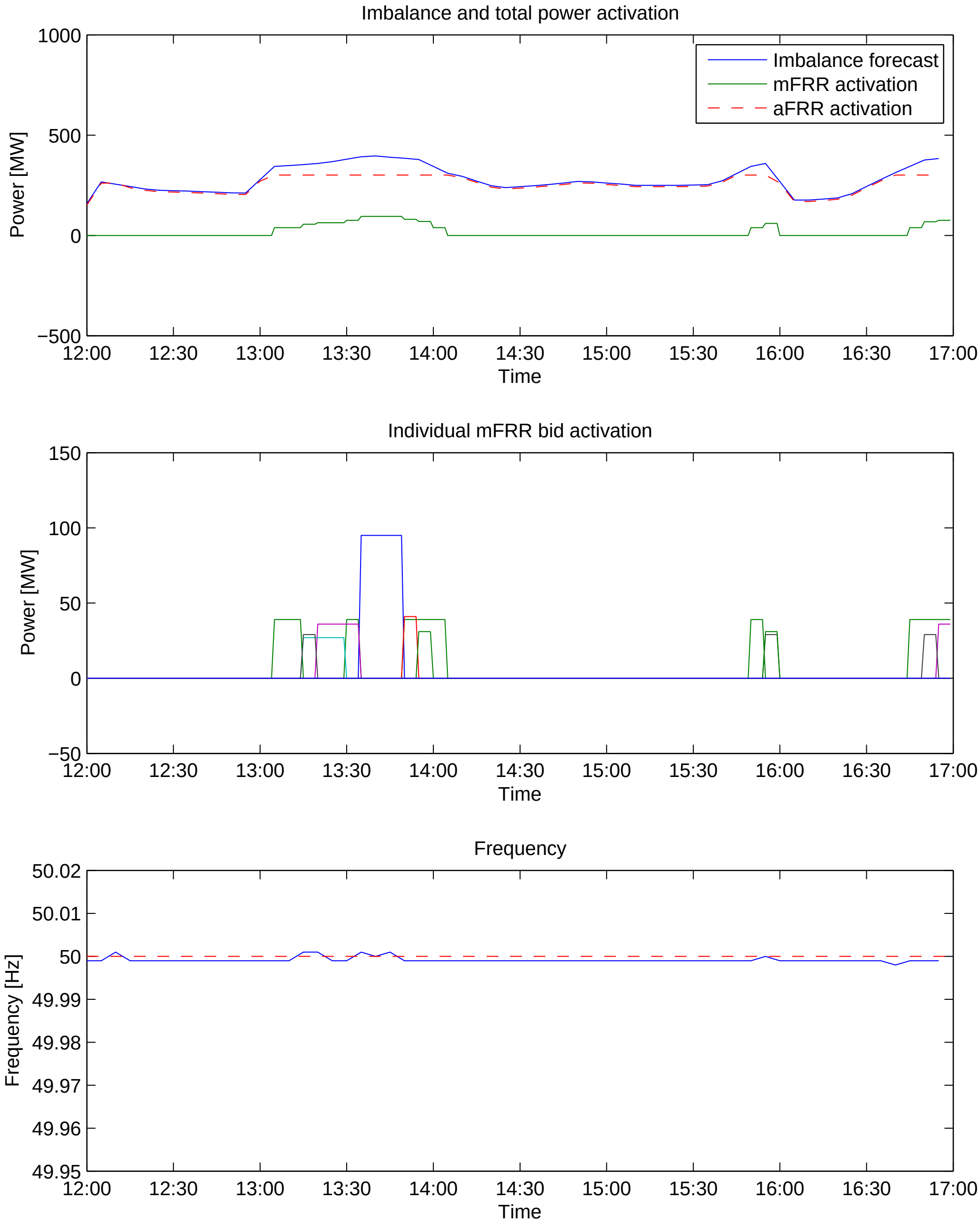


Figure 4.9: Activation of aFRR and mFRR from the Afternoon Base Case scenario.

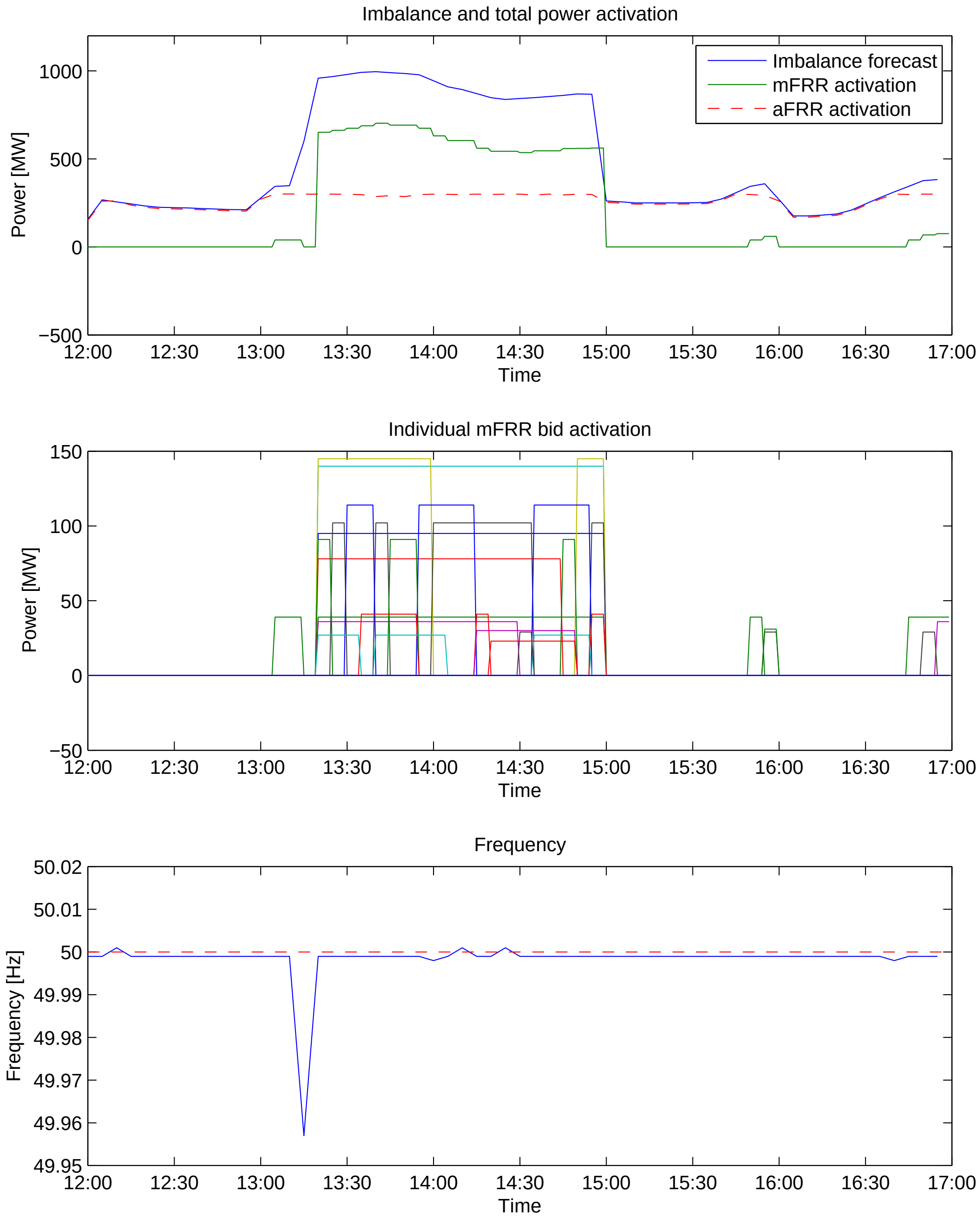


Figure 4.10: Activation of aFRR and mFRR from the Afternoon Generator Outage scenario.

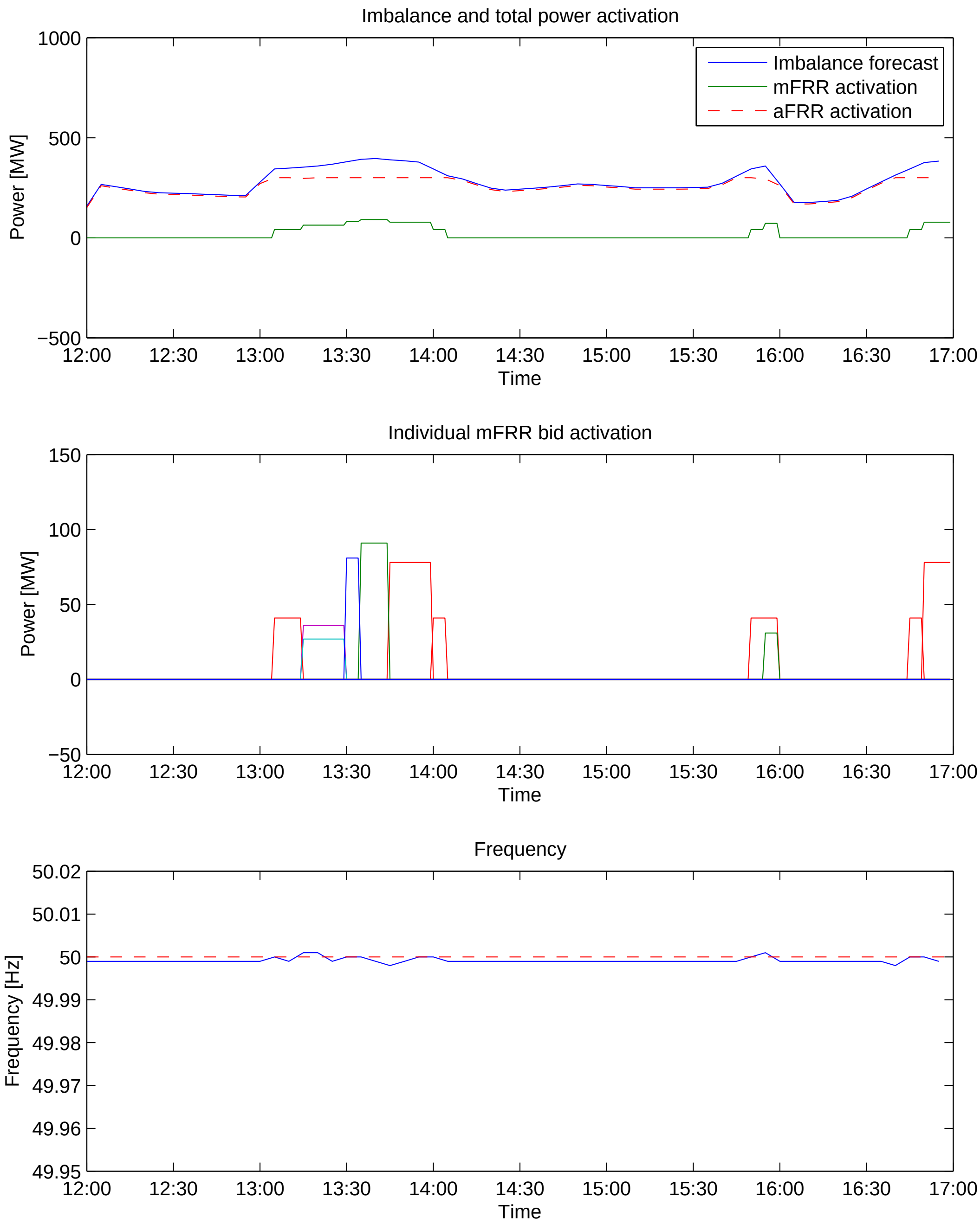


Figure 4.11: Activation of aFRR and mFRR from the Afternoon No P5 scenario.

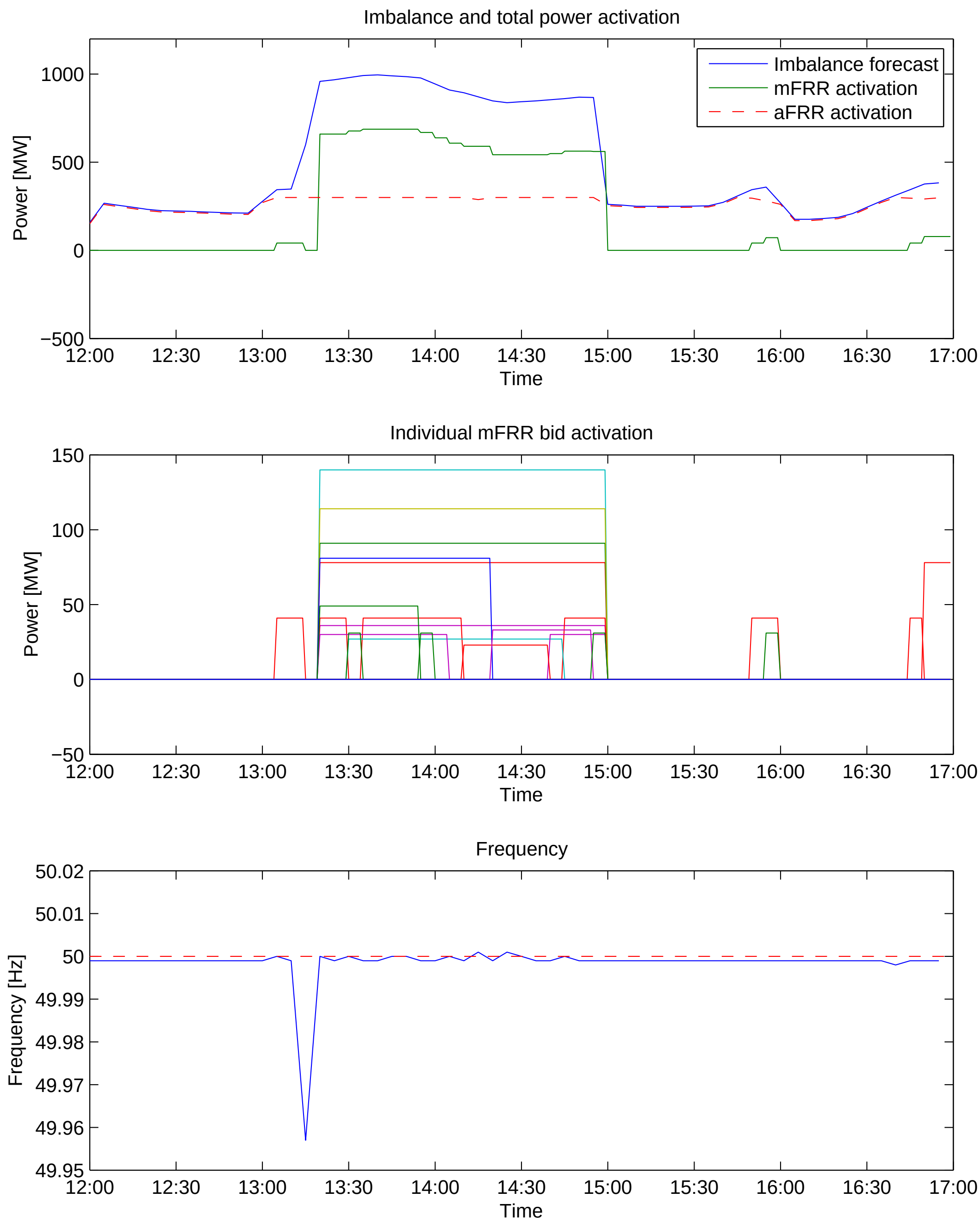


Figure 4.12: Activation of aFRR and mFRR from the Afternoon No P5 Generator Outage scenario.

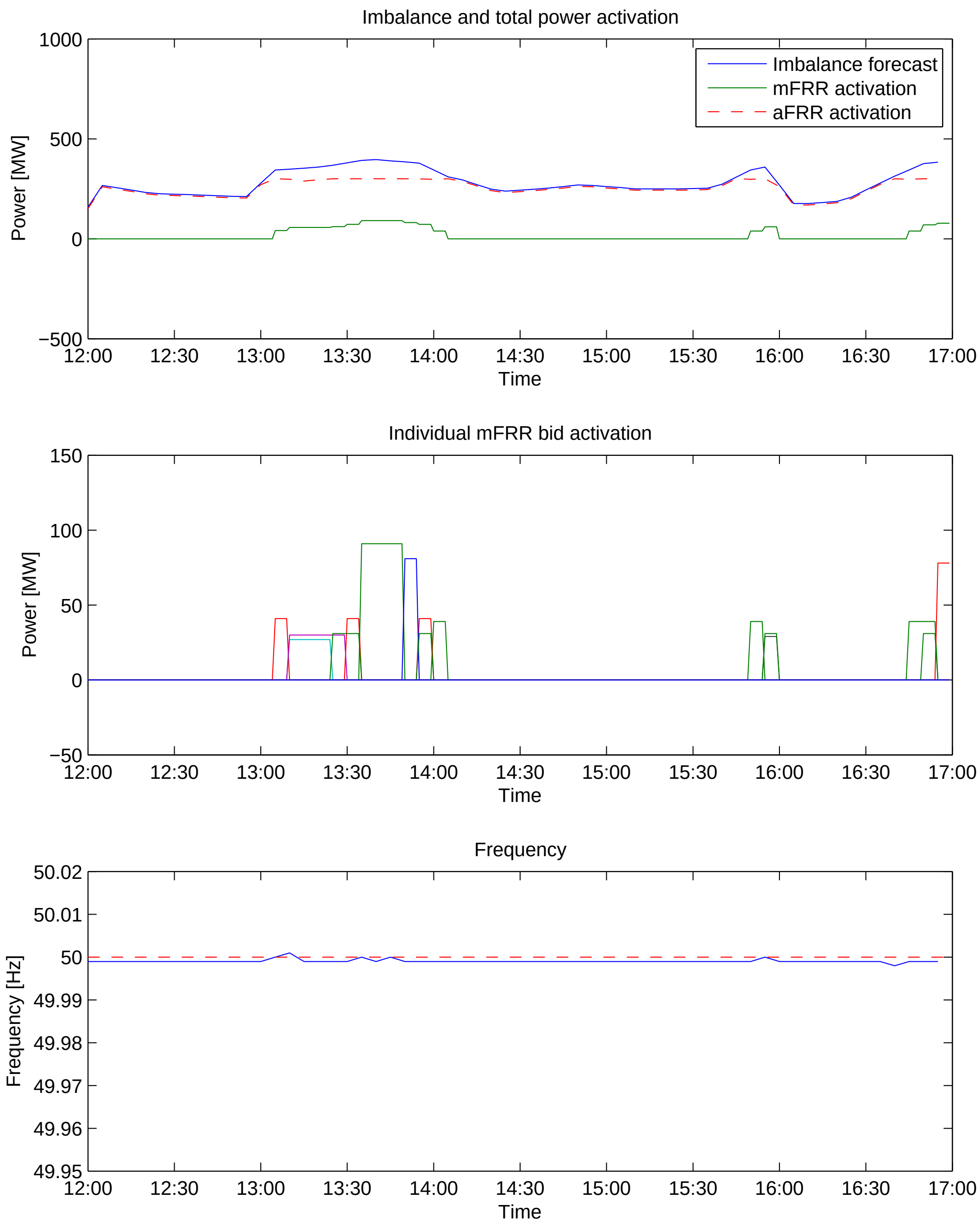


Figure 4.13: Activation of aFRR and mFRR from the Afternoon Some Bids Unav. scenario.

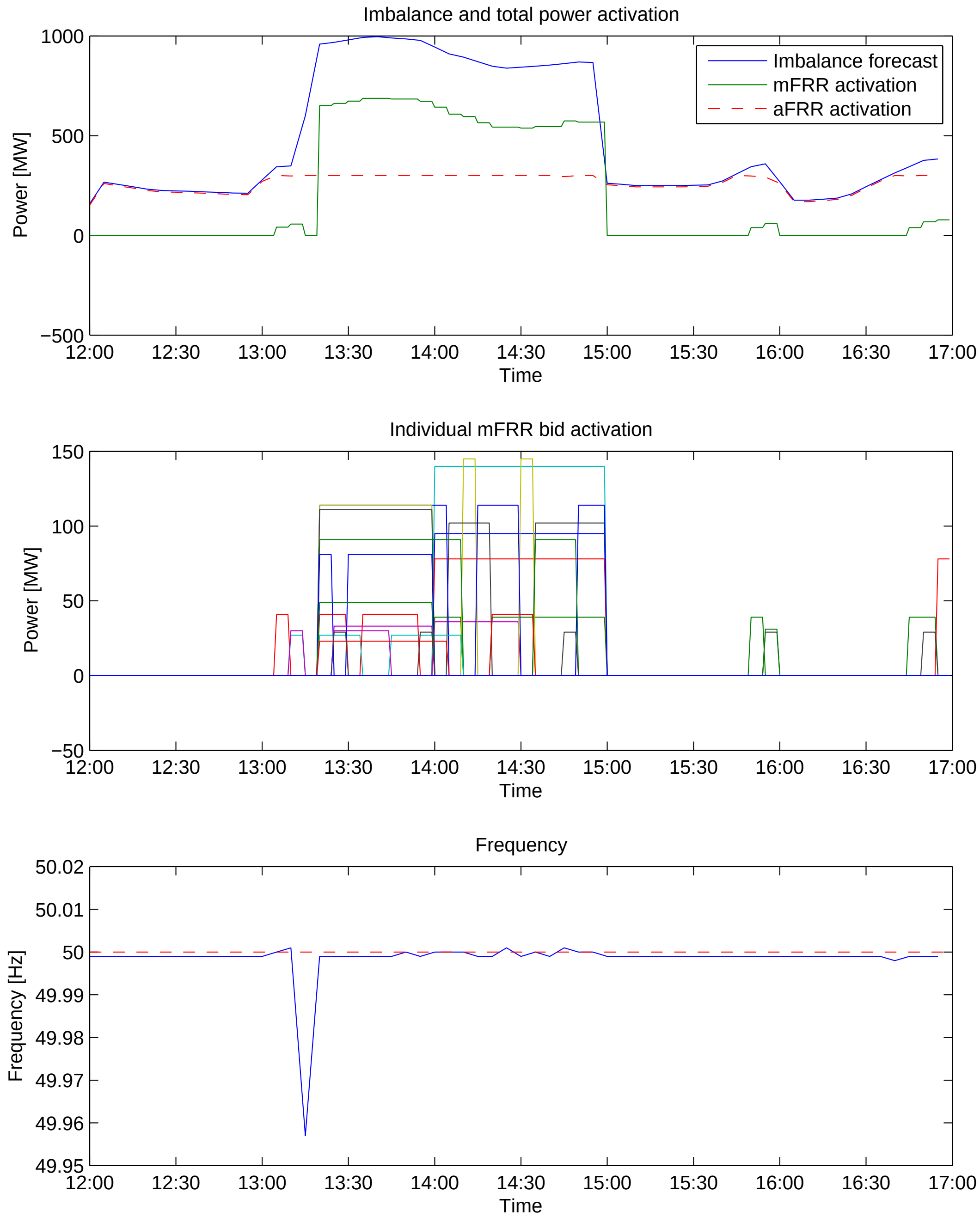


Figure 4.14: Activation of aFRR and mFRR from the Afternoon Some Bids Unav. Generator Outage scenario.

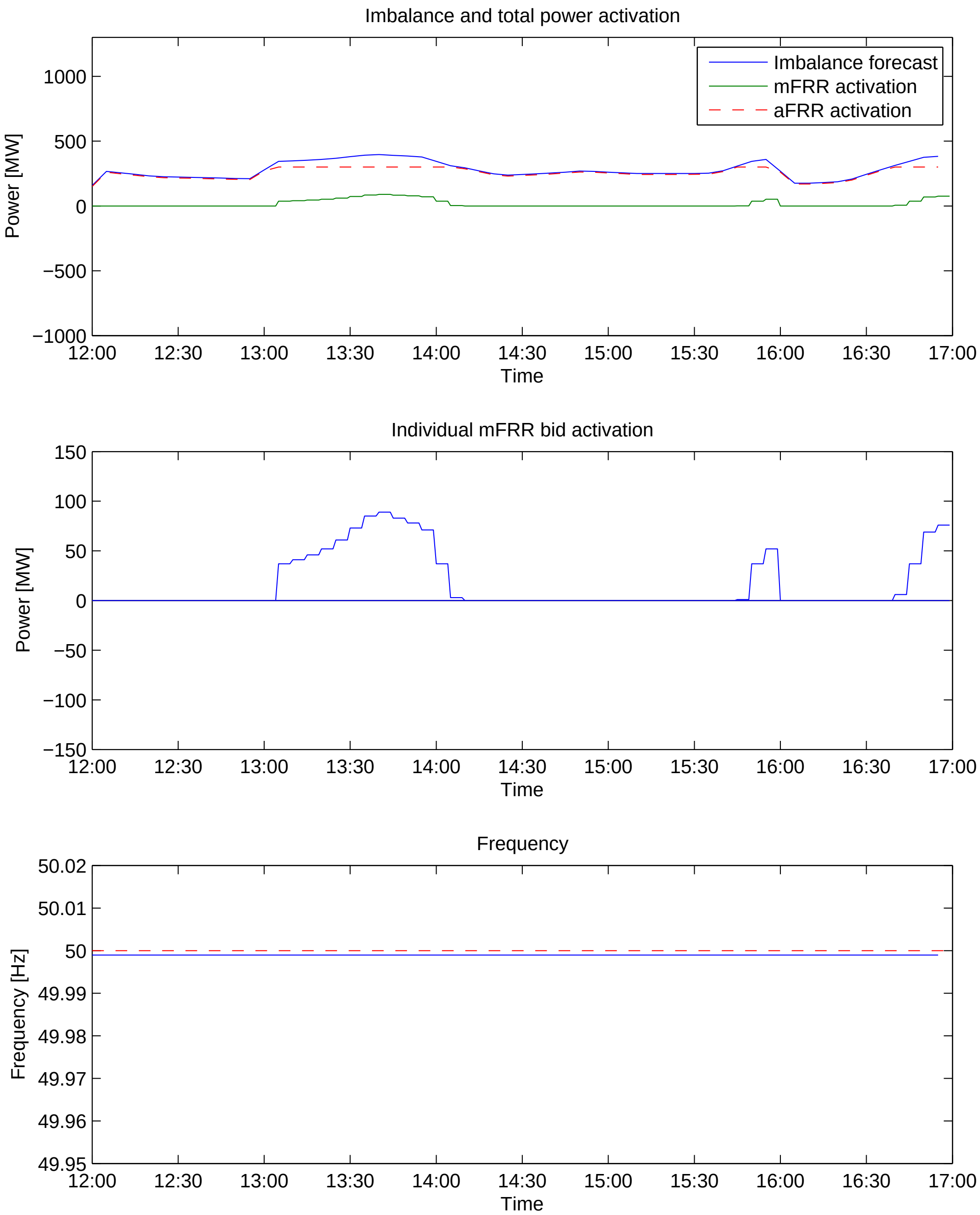


Figure 4.15: Activation of aFRR and mFRR from the Afternoon Fluid Profile scenario.

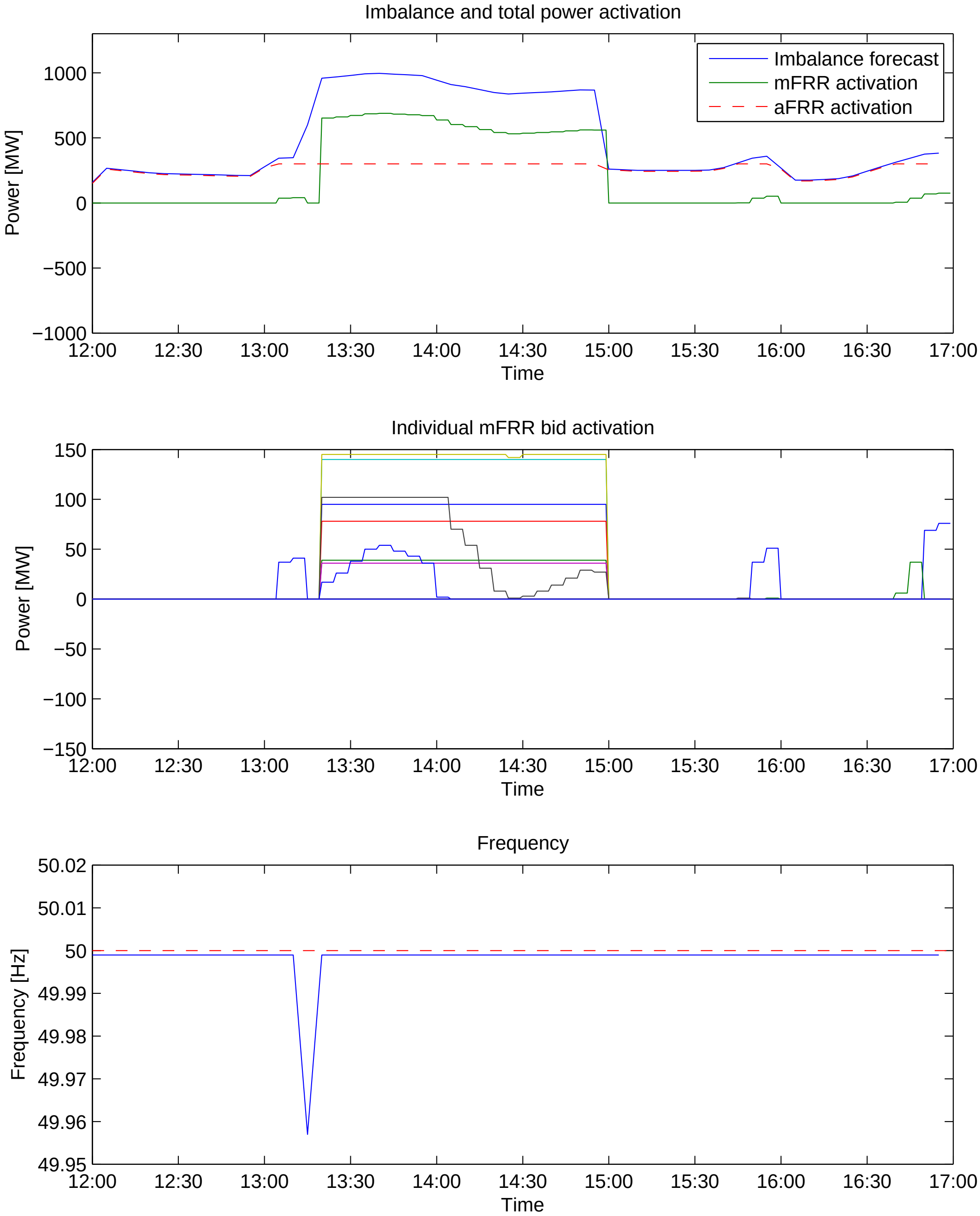


Figure 4.16: Activation of aFRR and mFRR from the Afternoon Fluid Profile Generator Outage scenario.

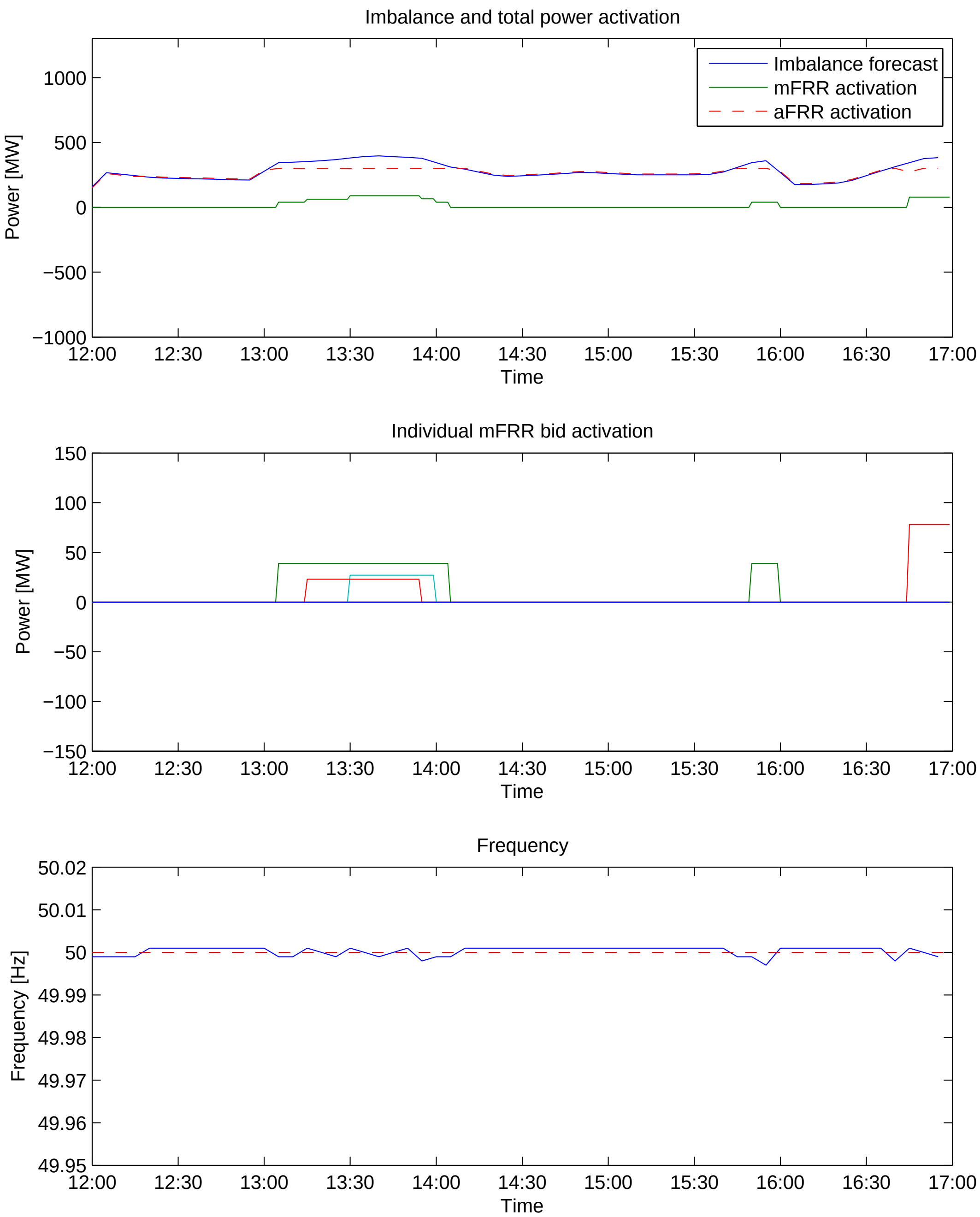


Figure 4.17: Activation of aFRR and mFRR from the Afternoon Fewer Instructions scenario.

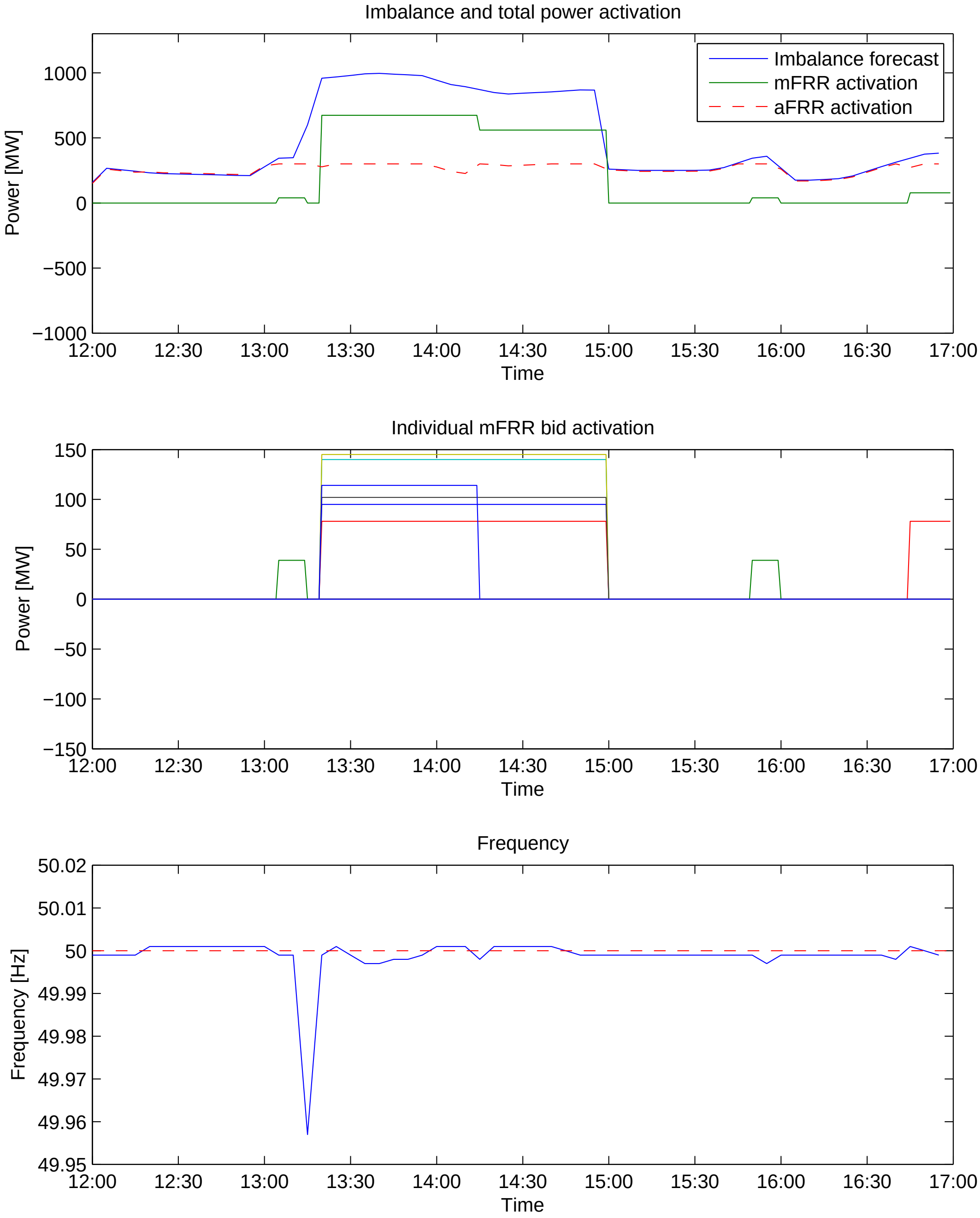


Figure 4.18: Activation of aFRR and mFRR from the Afternoon Fewer Instructions Generator Outage scenario.

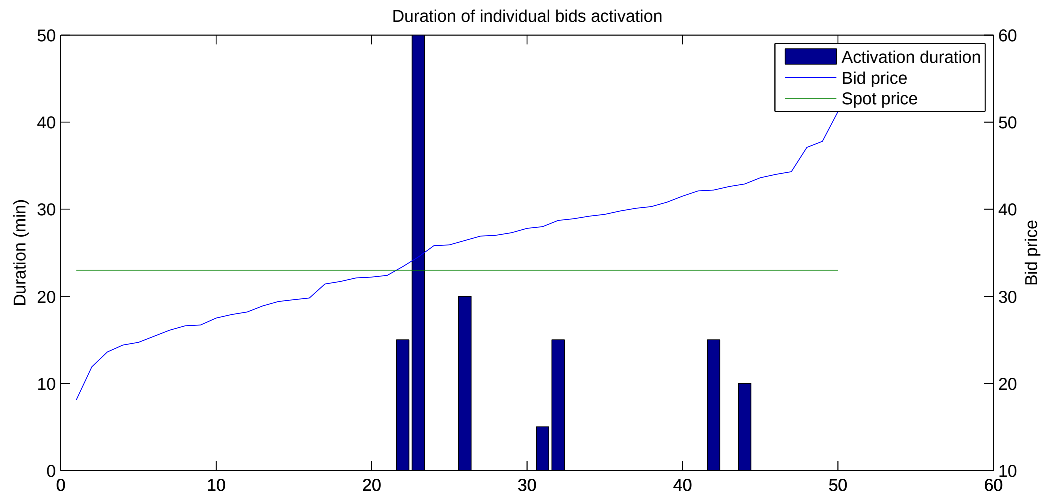


Figure 4.19: Activation duration of individual bids from the Afternoon Base Case scenario.

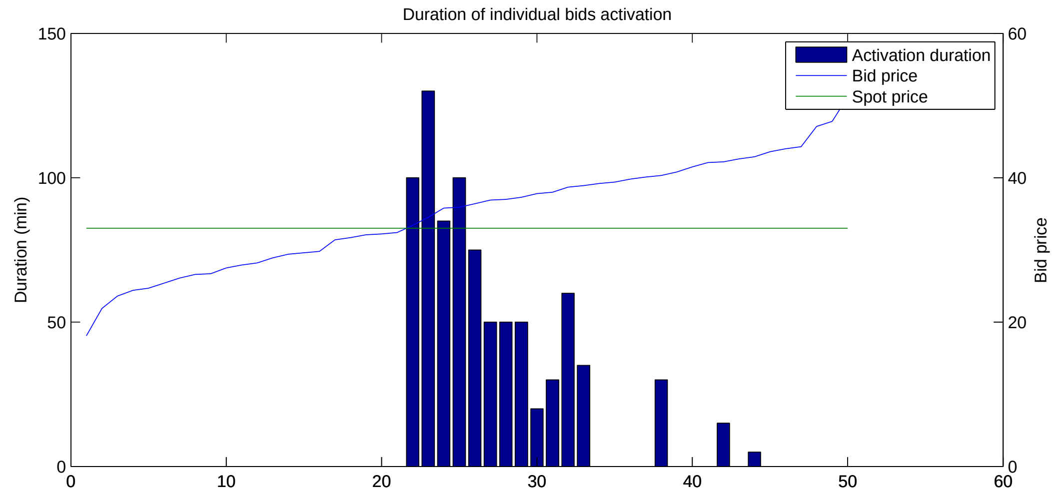


Figure 4.20: Activation duration of individual bids from the Afternoon Generator Outage scenario.

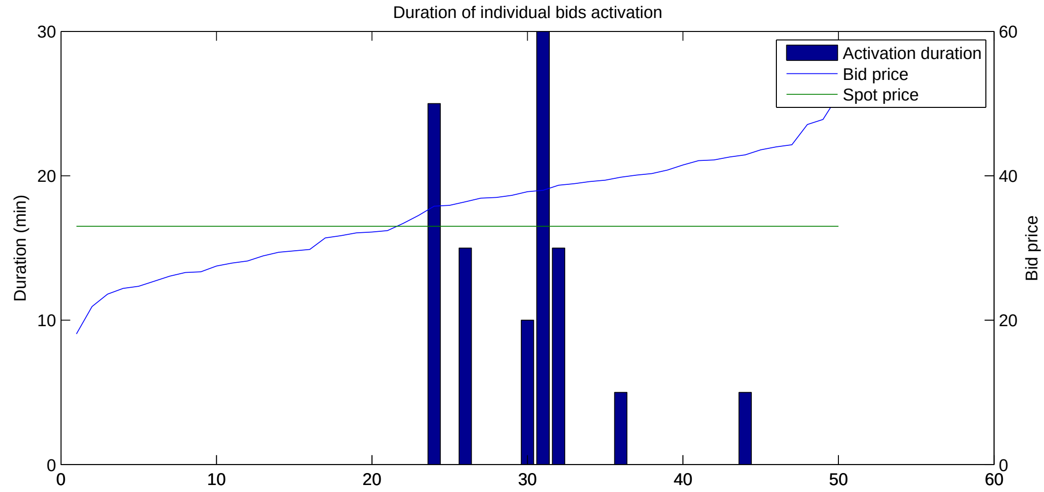


Figure 4.21: Activation duration of individual bids from the Afternoon No P5 scenario.

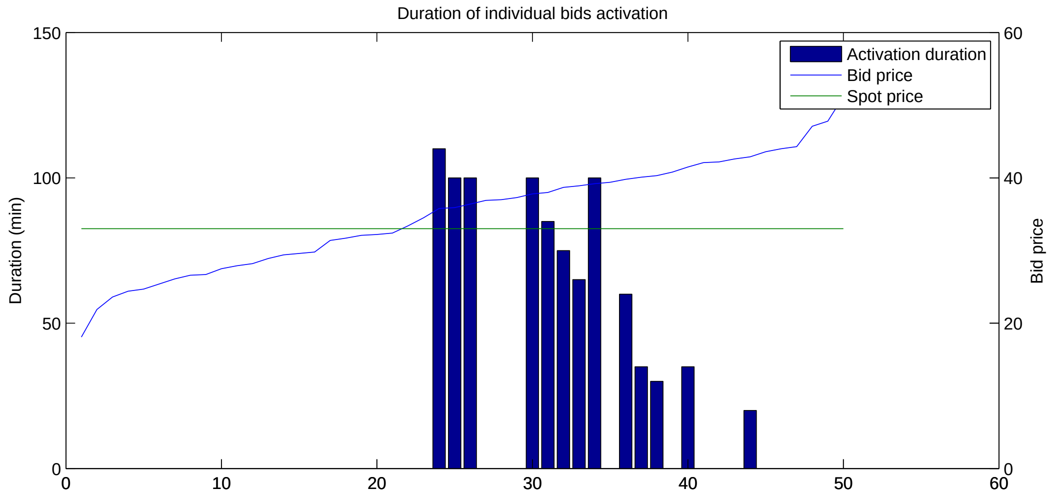


Figure 4.22: Activation duration of individual bids from the Afternoon No P5 Generator Outage scenario.

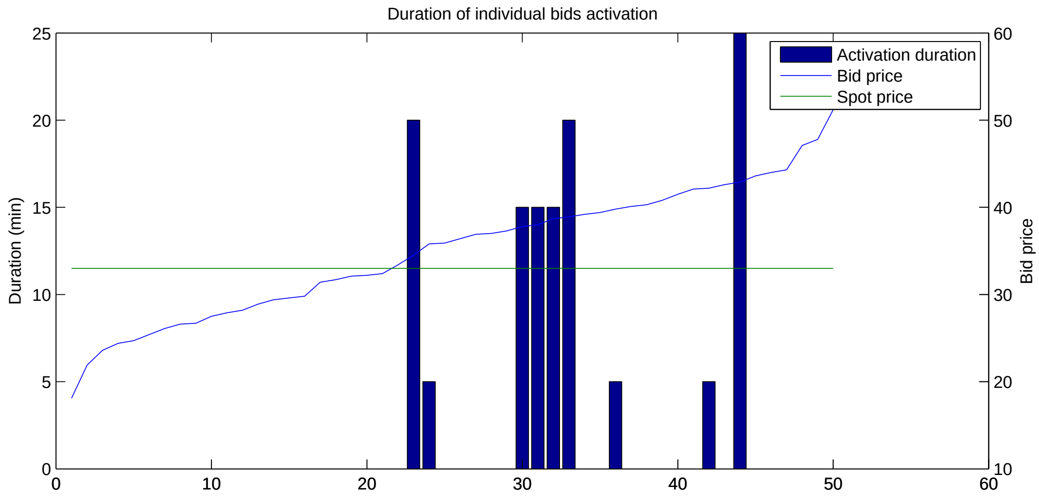


Figure 4.23: Activation duration of individual bids from the Afternoon Some Bids Unav. scenario.

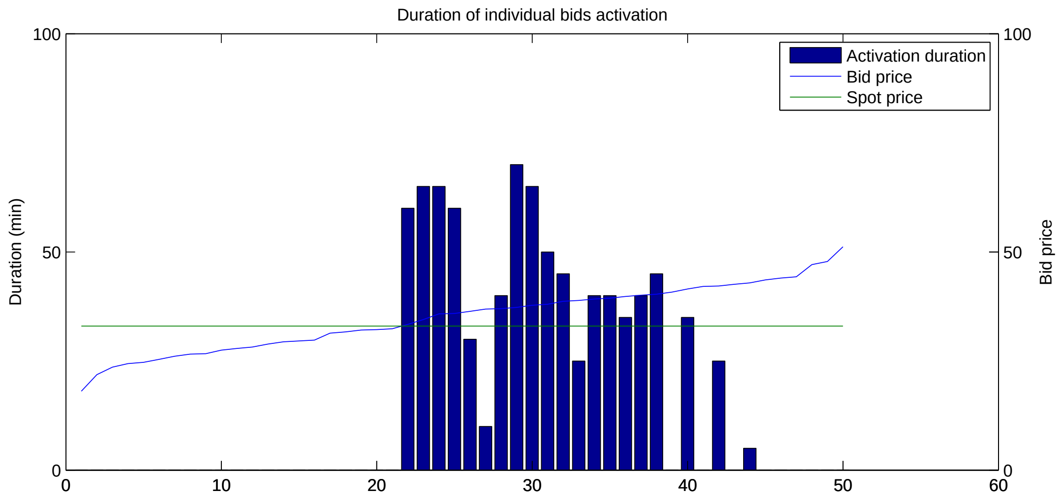


Figure 4.24: Activation duration of individual bids from the Afternoon Some Bids Unav. Generator Outage scenario.

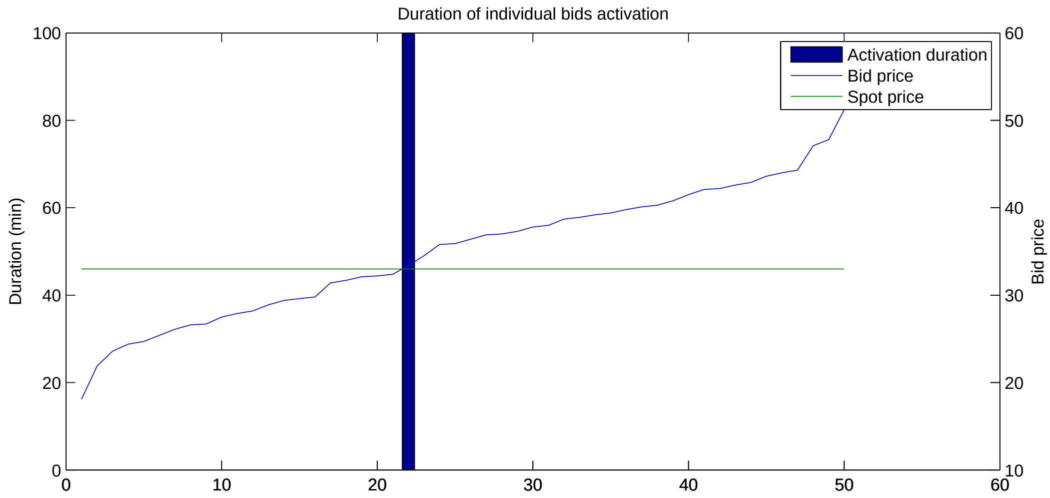


Figure 4.25: Activation duration of individual bids from the Afternoon Fluid Profile scenario.

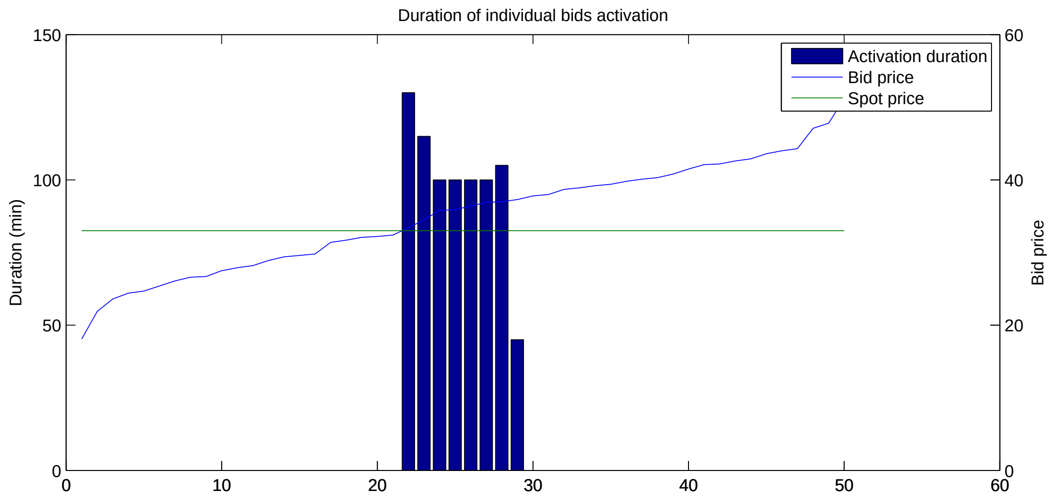


Figure 4.26: Activation duration of individual bids from the Afternoon Fluid Profile Generator Outage scenario.

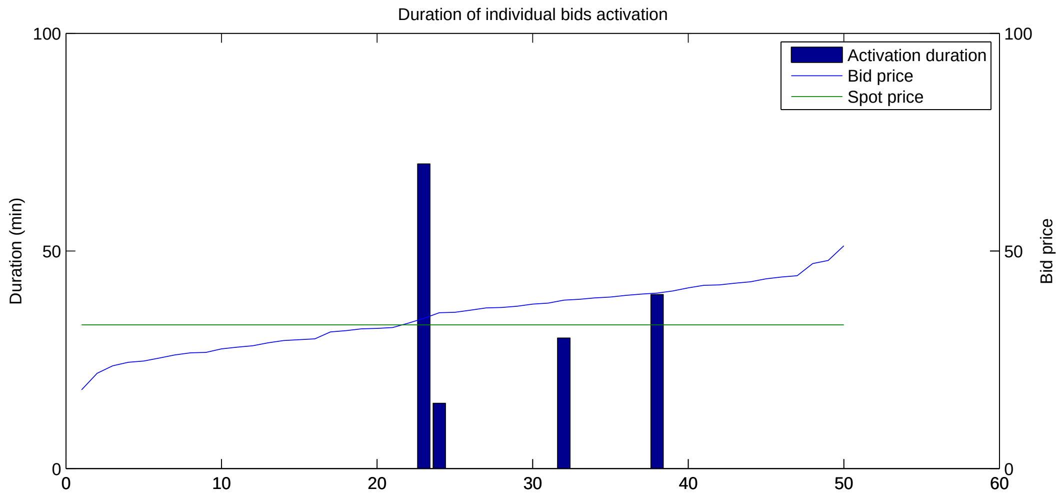


Figure 4.27: Activation duration of individual bids from the Afternoon Fewer Instructions scenario.

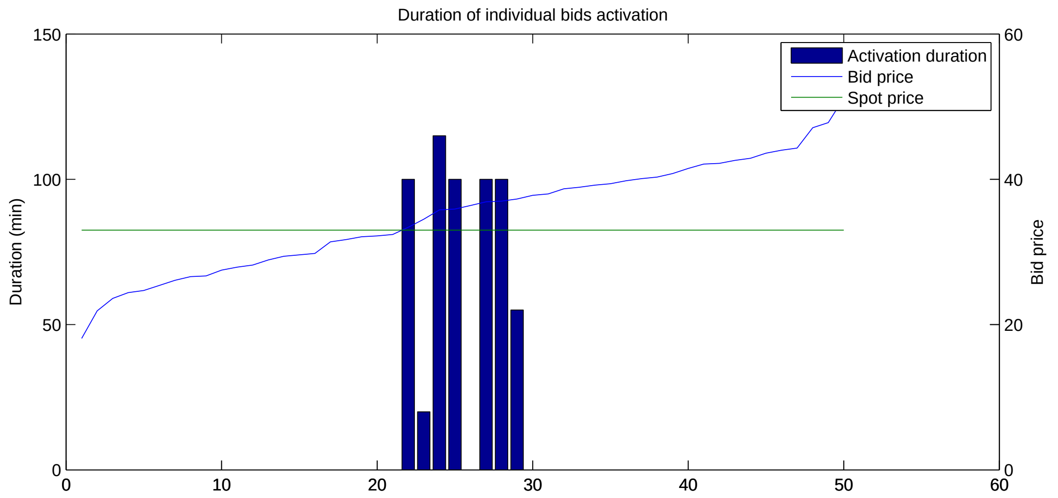


Figure 4.28: Activation duration of individual bids from the Afternoon Fewer Instructions Generator Outage scenario.

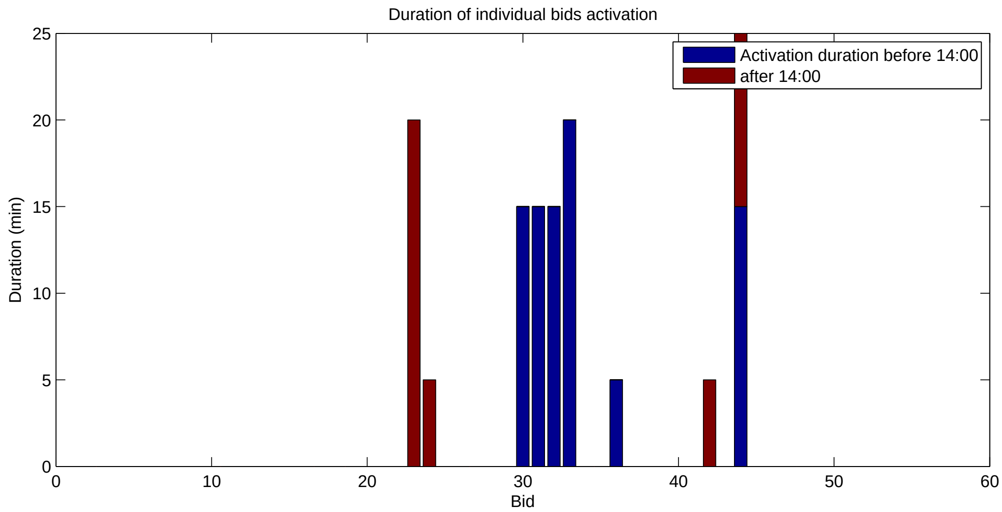


Figure 4.29: Activation duration of individual bids from the Afternoon Some Bids Unav. scenario before and after 14:00.

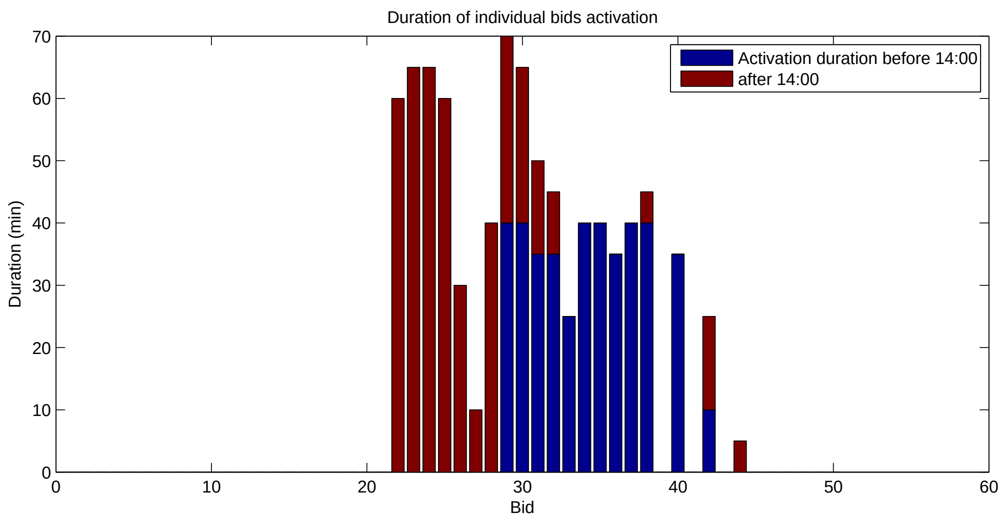


Figure 4.30: Activation duration of individual bids from the Afternoon Some Bids Unav. Generator Outage scenario before and after 14:00.

Table 4.5: Cost results for the different Afternoon scenarios

| **Scenario** | **mFRR activation cost [€]** | **Freq. dev. penalty cost [€]** | **aFRR shadow price [€/MW]** | **No. of act. marginal value [€]** |
|---|---|---|---|---|
| Afternoon Base Case | 3 308 | 157 | 81 | 0 |
| Afternoon Generator Outage | 37 629 | 4 500 | 139 | 65 |
| Afternoon No P5 | 3 484 | 214 | 102 | 8 |
| Afternoon No P5 Generator Outage | 39 455 | 4 357 | 18 | 70 |
| Afternoon Bids Unav. | 3 506 | 157 | 90 | 1 |
| Afternoon Bids Unav. Generator Outage | 38 886 | 4 371 | 165 | 24 |
| Afternoon Fluid Profile | 2 878 | 0 | 56 | 79 |
| Afternoon Fluid Profile Generator Outage | 37 059 | 4 186 | 102 | 0 |
| Afternoon Fewer Instr. | 3 408 | 429 | 105 | 166 |
| Afternoon Fewer Instr. Generator Outage | 38 347 | 5 114 | 157 | 862 |

Table 4.6: Activation volume results for the different Afternoon scenarios

| **Scenario** | **mFRR volume upwards [MWh]** | **mFRR volume down-wards [MWh]** | **aFRR volume upwards [MWh]** | **aFRR volume down-wards [MWh]** | **aFRR satura-tion [% of time]** |
|---|---|---|---|---|---|
| Afternoon Base Case | 91 | 0 | 1 276 | 0 | 33 |
| Afternoon Generator Outage | 1 049 | 0 | 1 309 | 0 | 25 |
| Afternoon No P5 | 93 | 0 | 1 273 | 0 | 30 |
| Afternoon No P5 Gener-ator Outage | 1 053 | 0 | 1 309 | 0 | 40 |
| Afternoon Bids Unav. | 91 | 0 | 1 272 | 0 | 22 |
| Afternoon Bids Unav. Generator Outage | 1 051 | 0 | 1 312 | 0 | 40 |
| Afternoon Fluid Profile | 86 | 0 | 1 274 | 0 | 33 |
| Afternoon Fluid Profile Generator Outage | 1 043 | 0 | 1 313 | 0 | 50 |
| Afternoon Fewer Instr. | 94 | 0 | 1 313 | 0 | 30 |
| Afternoon Fewer Instr. Generator Outage | 1 070 | 0 | 1 304 | 0 | 35 |

Table 4.7: mFRR activation duration (in minutes) for the different Standard Products and Afternoon scenarios

| Scenario | P1 | P2 | P4 | P5 | Total |
|---|---|---|---|---|---|
| Afternoon Base Case | 35 | 0 | 15 | 80 | 130 |
| Afternoon Generator Outage | 255 | 30 | 155 | 395 | 835 |
| Afternoon No P5 | 55 | 0 | 50 | 0 | 105 |
| Afternoon No P5 Generator Outage | 350 | 100 | 465 | 0 | 915 |
| Afternoon Bids Unav. | 40 | 0 | 60 | 25 | 125 |
| Afternoon Bids Unav. Generator Outage | 165 | 120 | 255 | 310 | 850 |
| Afternoon Fluid Profile | 0 | 0 | 0 | 100 | 100 |
| Afternoon Fluid Profile Generator Outage | 200 | 0 | 100 | 495 | 795 |
| Afternoon Fewer Instr. | 45 | 40 | 0 | 70 | 155 |
| Afternoon Fewer Instr. Generator Outage | 115 | 0 | 100 | 375 | 590 |

Table 4.8: Total number of mFRR actvations for the different Standard Products and Afternoon scenarios

| Scenario | P1 | P2 | P4 | P5 | Total |
|---|---|---|---|---|---|
| Afternoon Base Case | 3 | 0 | 3 | 9 | 15 |
| Afternoon Generator Outage | 7 | 1 | 8 | 17 | 33 |
| Afternoon No P5 | 4 | 0 | 7 | 0 | 11 |
| Afternoon No P5 Generator Outage | 6 | 3 | 14 | 0 | 23 |
| Afternoon Bids Unav. | 3 | 0 | 9 | 4 | 16 |
| Afternoon Bids Unav. Generator Outage | 8 | 3 | 11 | 18 | 40 |
| Afternoon Fluid Profile | 0 | 0 | 0 | 3 | 3 |
| Afternoon Fluid Profile Generator Outage | 2 | 0 | 1 | 10 | 13 |
| Afternoon Fewer Instr. | 2 | 1 | 0 | 2 | 5 |
| Afternoon Fewer Instr. Generator Outage | 2 | 0 | 1 | 6 | 9 |

# Chapter 5

# Discussion

## 5.1 Introduction

In this Chapter, the data and observations from Chapter 4 will be interpreted and discussed.

A summary on the most important assumptions and their influence on the model behaviour and results in general is given in Section 5.2. Errors discovered during the final stages of analysis are discussed in Section 5.3. Results from the Morning Scenarios and the Afternoon Scenarios are discussed in Section 5.4 and 5.5, respectively. Observations will be discussed for each scenario, as well as in separate sections comparing the costs, volumes and activations for the relevant scenarios. A short comment made in retrospect is included in Section 5.6. The impact and relevance of results and observations on European Policy on balancing markets is discussed in Section 5.7, before suggestions on future work and improvements are summarized in Section 5.8.

## 5.2 Important Assumptions and their Influence

In the optimization model presented in this thesis, as in all other models, assumptions and simplifications are made to reduce complexity in modelling, computation and analysis. The quality and validity of solutions obtained from the model will depend on the quality and validity of the assumptions made, together with their influence on the model behaviour. In this section, some of the most important assumptions and simplifications are discussed.

### 5.2.1 Uncertainty and the Deterministic Optimization Formulation

The optimization model solves the problem deterministically, i.e. it assumes the future to be fully and perfectly known. In reality, an imbalance forecast does not provide perfect information on the future imbalance, as the power system is exposed to errors and random variations.

This uncertainty could be taken into account using a probability distribution rather than a single trajectory for the imbalance forecast, combined with a stochastic formulation of the optimization problem. The single trajectory imbalance forecast can be seen as equivalent to the expected values for a set of random variables. The deterministic solution based on expected values will be optimal if the future turn out to be just as expected, i.e. all random variables are at their expected value. Using this solution over the entire range of outcomes given by the probability distributions, not considering the random variation, will generally give a loss compared to using a stochastic solution. This difference is called the Value of the Stochastic Solution (VSS), as explained in [52, p. 9]. In addition, the Expected Value of Perfect Information (EVPI) describes the difference between the value between having perfect foresight before making any decisions and the stochastic solution.

The VSS compares the quality of the stochastic and deterministic solutions and depends on the probability distribution. Decreasing the uncertainty will lower the VSS, until VSS = 0 if there is no uncertainty.

In this report, the probability range of imbalance outcomes is not known, and the deterministic solution will generally not be applied to imbalance profiles differing from the forecast. Not considering the random variations in the imbalance profile is equivalent to an assumption of perfect information on the imbalance. If this assumption is correct, the deterministic solution will be optimal. If it is not correct, the results will provide an overestimation of the performance and efficiency of the model.

Due to the random variations in the power system, there is uncertainty in forecasts and the assumption of perfect information is not correct. However, on the very short term, such as the next 10-15 minutes, the uncertainty in forecasts is considered very low [32]. In real life, TSOs such as National Grid tend to rely on updated forecasts and measurements to re-optimize deterministic or heuristic solutions at short intervals, rather than using stochastic formulations [30].

Due to the low level of uncertainty in the very short term, decisions made deterministically for this period will be near-optimal. Longer-ahead decisions, such as a bid being scheduled to start in two hours time is not necessarily optimal, but as the model may re-decide at a later stage, the final decision on this specific activation will be made at a stage with lower level of uncertainty. The optimization model described in this report is able to re-optimize the activation schedules for an updated imbalance at a later stage.

The decisions made by the model have a horizon from 5 minutes to about an hour. This means some decisions will be passed on as sunk decisions into the next re-optimization. Typical sunk decisions are unit commitment decisions, such as bids previously activated with a minimum duration requirement not yet fulfilled. Thus the decisions with horizons longer than the re-optimization interval provides a coupling between the time steps in the optimization. This coupling makes it necessary to optimize with a horizon larger than the length of a single time step. Sunk decisions are formulated as additional constraints which may be binding when re-optimizing activation schedules for updated forecasts, in which case they will lead to a deterioration of the objective function value [4, p. 110].

### 5.2.2 Ramp Rates and the Block Product Formulation

As mentioned in Section 3.2.5, the balancing energy activation model uses a block bid formulation, i.e. it assumes an infinite ramp of the power delivery for the activated bids. This simplification is inaccurate with regards to real ramp rate capabilities. In reality the power delivered would follow smoother curves due to the limited ramping abilities of

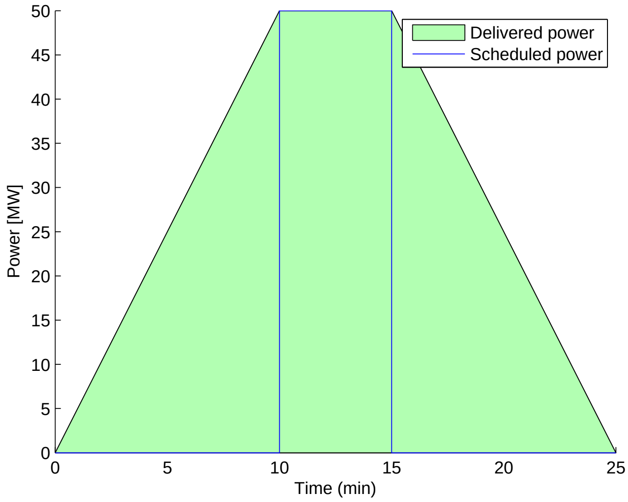


Figure 5.1: Differerence between scheduled and delivered power in the extreme case for a P4 bid.

generation units and portfolios.

More importantly, an activated bid will in real life deliver a substantial amount of balancing energy during its ramping phase. This energy is not taken into account by the optimization model. The extreme case is shown in Fig. 5.1 for a 50 MW P4 bid. Here, 10 minutes are used for both activation and deactivation, while the bid is only delivering at full power for 5 minutes. This activation satisfies the Standard Product definitions (with a small adjustment for the preparation period). The scheduled balancing energy is 50 MW for 5 minutes: 4.2 MWh, while the actual energy delivered may be up to 12.5 MWh, or three times higher, in the extreme case.

The actual amount of energy depends on the actual ramping profile of the activated bid. Some bids may be able to ramp much faster than the requirement on full activation time from 2.2, in which case the amount of energy delivered from ramping will be small compared to the scheduled activation. Similarly, for bids activated for longer than their minimum duration, the share of energy delivered from the ramping phases will be lower.

The use of block products compared to *physical* products (which have a ramping profile), is a topic of discussion for ENTSO-E, as they both have strength and weaknesses. The block formulation is simple and straightforward, but does not account for the energy delivered during ramping. The physical formulation, on the other hand, includes a ramping profile, and thus includes the energy delivered during ramping in the optimization. The problem with physical profiles is, however, not only the added complexity, but also the fact that the physical profile in the formulation not necessarily matches the actual ramping profile of the bid, in which case the scheduled energy delivery will still be inaccurate. This inaccuracy can be removed by requiring BSPs to follow the defined ramping profile, or by knowing the ramp rates of each of the bid providers, as suggested for P3 in Table 2.2. In either case, the uncertainty related to energy delivered during ramping makes longer bids more attractive [30] from an operations perspective, although this is not necessarily most efficient.

Using block products in the balancing energy activation model influences the model behaviour in two important ways. Firstly, the difference between scheduled and actual delivered energy from balancing activation will lead to balancing energy volumes being larger than the imbalance forecast in some cases, which is suboptimal. Secondly, the block bid formulation decreases coupling between time steps in that short products may be scheduled to deliver power during only one time step, while they in reality would influence power delivery on the time steps both before and after. This means the short products (P4 and P5) are more flexible from a model point of view in a block formulation compared to a physical formulation.

This influence on model behaviour means the schedules found in Chapter 4 would in real life deliver more energy than needed to restore frequency. The frequency calculation will depend also on the aFRR activation, which will adapt to the power delivered by mFRR. For outage cases, energy delivered during ramping will reduce the imbalance even before full activation is reached, meaning frequency will be restored faster in real life than in the schedule.

### 5.2.3 Simplified aFRR Implementation

As was described in Section sec:methodologyAFRR, the model takes the behaviour of aFRR into account through the use of the $x_t$ decision variable. This formulation allows the aFRR activation to be determined by the optimization for each time step. It has no constraint on ramping rates, but is limited to a capacity limit of 300 MW for both upward and downward regulation.

#### Ramp Rates and Flexibility

This implementation rests on the assumption that aFRR activation would in real life adapt to the imbalance situation by delivering as much power as needed to cover the instantaneous imbalance, subject to its capacity limits. This includes being able to ramp between required activation levels in 5 minute time steps. In principle, this requires ramp rate capability of up to 120 MW/min in the extreme case.

In real systems, the activation of aFRR is controlled by a LFC mechanism as described in Section 2.3.4. First of all, this is a continuously updated, rather than a discrete process. There is also a certain delay and time until delivery, as given in [24] for the Norwegian system. On the continent, the activation of aFRR is generally slower, and the LFC mechanism responds not only to frequency, but also to tie-line flow errors through the ACE.

In the Nordic system, the aFRR control signal is the system frequency deviation, which can be seen as roughly proportional to the power imbalance through the use of the frequency bias $\lambda$. For such a case, the adapting aFRR behaviour is not unreasonable. It should be noted, however, that the value of the frequency bias is, however, not necessarily constant for different ranges of frequency deviations or during different times of the year. The delays, turn times and time constants related to ramping of aFRR are shorter than the bid lengths, which means the aFRR dispatch for different time steps is coupled mainly through the limited ramp rate. There is no ramp rate constraint in the balancing energy activation model, but from the limits on bid and step sizes, a worst-case ramp rate is estimated to be at least 300 MW for a period of 5 minutes. Such steps in set points would perhaps only occur following large unexpected outages.

Including a ramp rate constraint would in principle introduce a coupling between the aFRR dispatch of different time periods, but would in practice very rarely be binding. A binding constraint will make the model speculate in the aFRR dispatch for different time steps simultaneously. This will give a cost optimal solution, but does not resemble the behaviour of the PI controller used for the LFC mechanism.

The unconstrained ramp rate of the aFRR implementation will influence results to some extent. This is due to the capability of aFRR activation to some extent due to its additional flexibility compared to its real counterpart. It will, however, have low impact on the fundamental behaviour of the aFRR activation algorithm compared to the frequency-only Nordic aFRR system.

### Cost of aFRR activation

The most important impact on model behaviour occurs from the modelling of aFRR as a free resource. As the model sees no cost associated with the aFRR volume, a minimum cost solution will generally cover as much of the imbalance as possible using the aFRR activation. This means mFRR will be activated only when the forecast imbalance is larger than the aFRR capacity. Examples of this behaviour can be seen throughout the activation schedules found in the results, cf. Figs. 4.1 and 4.10. mFRR bids are scheduled to follow the imbalance profile closely to allow the free aFRR resource to be fully utilized.

Although this is a cost optimal way to schedule balancing energy from the model perspective, it conflicts the underlying control philosophy of using the fastest reserves for the fastest disturbances. When the aFRR capacity is fully utilized, the capability of fast restoration is exhausted in one direction, and the system is vulnerable to short term deviations from the imbalance forecast. The model assumes perfect information and therefore does not see the risk related to operating at the limit of aFRR capacity. In addition, from [24], the maximum duration of a set point is 30 minutes, which means continuously utilizing all aFRR capacity is not allowed from a operations point of view.

The no-cost implementation of aFRR does not arise from an erroneous assumption of aFRR having no costs related to activation volumes. Although a large part of the costs related to providing aFRR is the capacity cost, there is also an operational cost related to the volumes delivered. The volume cost for aFRR is in Norway settled between the providing BSP and the TSO as a single buyer, with the price given by the prices in the RPM. The no-cost implementation arises from the assumption that aFRR volumes are not scheduled in advance following a cost comparison with other alternatives. It simply follows the control signal given by the frequency.

A number of alternative implementations may be used to change the behaviour of aFRR in the model. Adding a volume cost on the aFRR activation could be done by simply associating the $x_t$ variable with a set of cost parameters in the objective function. In the simplest case, there could be a single price on use of aFRR, or separate prices for each direction. Adding such a cost term in the objective function will influence the optimization, as the model will compare the costs and benefits of aFRR and mFRR activation before creating a schedule. If the aFRR price is set at a level higher than the mFRR price levels, the model will also compare the aFRR cost with the frequency deviation penalty costs. Penalty costs are estimated to be roughly 4 times the bid price for mFRR upward regulation for small imbalances. For aFRR price levels between mFRR and the penalty costs, the aFRR will be seen as a generation of *last resort* to avoid frequency deviations, and the model will try to schedule mFRR to avoid activating aFRR. As such a schedule would restore frequency with very low use of aFRR, providing aFRR margins that can be used for balancing short-term disturbances.

In short, from an optimization point of view, adding cost terms to aFRR activation is entirely equivalent to adding more penalty cost levels. In this regard, an aFRR volume price of zero is equivalent to a dead band on frequency deviation penalty costs. Adding a cost higher than zero would force the mFRR activation to cover more of the imbalance, but at the same time would depend on the penalty levels (as discussed in Section 5.2.4).

Another possibility is to limit the aFRR capacity available in the optimization. This is done simply by altering the $\overline{x}$ and $\underline{x}$ parameters. This will change the size of the dead band, but apart from this not change the principal behaviour of the model. It will, however, provide available aFRR margins to be used for short-term disturbances. The extreme case is limiting the aFRR capacity to 0, in which case the model will try to find a schedule which fits the imbalance profile using mFRR bids only.

As an example, the Morning Schedule Smoothing Scenario was run with no aFRR capacity available, leaving only the mFRR to follow the imbalance profile and avoid frequency deviations. The resulting activation schedule is shown in Fig. 5.2. Using a large amount of short activations, the model is able to find a schedule with negligible frequency deviations. This indicates the abundance of fast mFRR available in the fictive market, and also illustrates how balancing different time steps are to a large extent decoupled in the model.

A third option is to set a requirement on the share of balancing energy to be delivered from mFRR. This could be implemented in a few different ways, with the result that mFRR is forced to participate in balancing even if aFRR resources are not exhausted. Such a formulation would to some extent reflect the role of tertiary control in replacing the automatic reserves, as is the common practice, e.g. in [53]. The choices of the model would at the same time depend a lot on the parameters used in the implementation of the constraints.

The influence of the free aFRR resource on model behaviour is carried on to the results. Firstly, it can be argued that in a good solution, mFRR should make up a larger share of the total balancing energy volume. Secondly, the exhaustion of aFRR resources imposes a risk, which cost is not seen in the optimization due to the disregard of uncertainty. Thirdly, the model does not compare the operational cost of aFRR energy with the manual alternatives.

### 5.2.4 Frequency Deviation Penalty Costs

As described in Section 3.2.1, the estimated frequency deviation is penalized in the objective function. The frequency deviation is estimated using the instantaneous power imbalance and the frequency bias $\lambda$.

The use of frequency deviation penalty costs influences the model behaviour. Without the penalties, there would be no incentive for the optimization to restore frequency. As mentioned in Chapter 3, using constraints on frequency range would give different behaviour and in some cases make the optimization problem infeasible. The general purpose

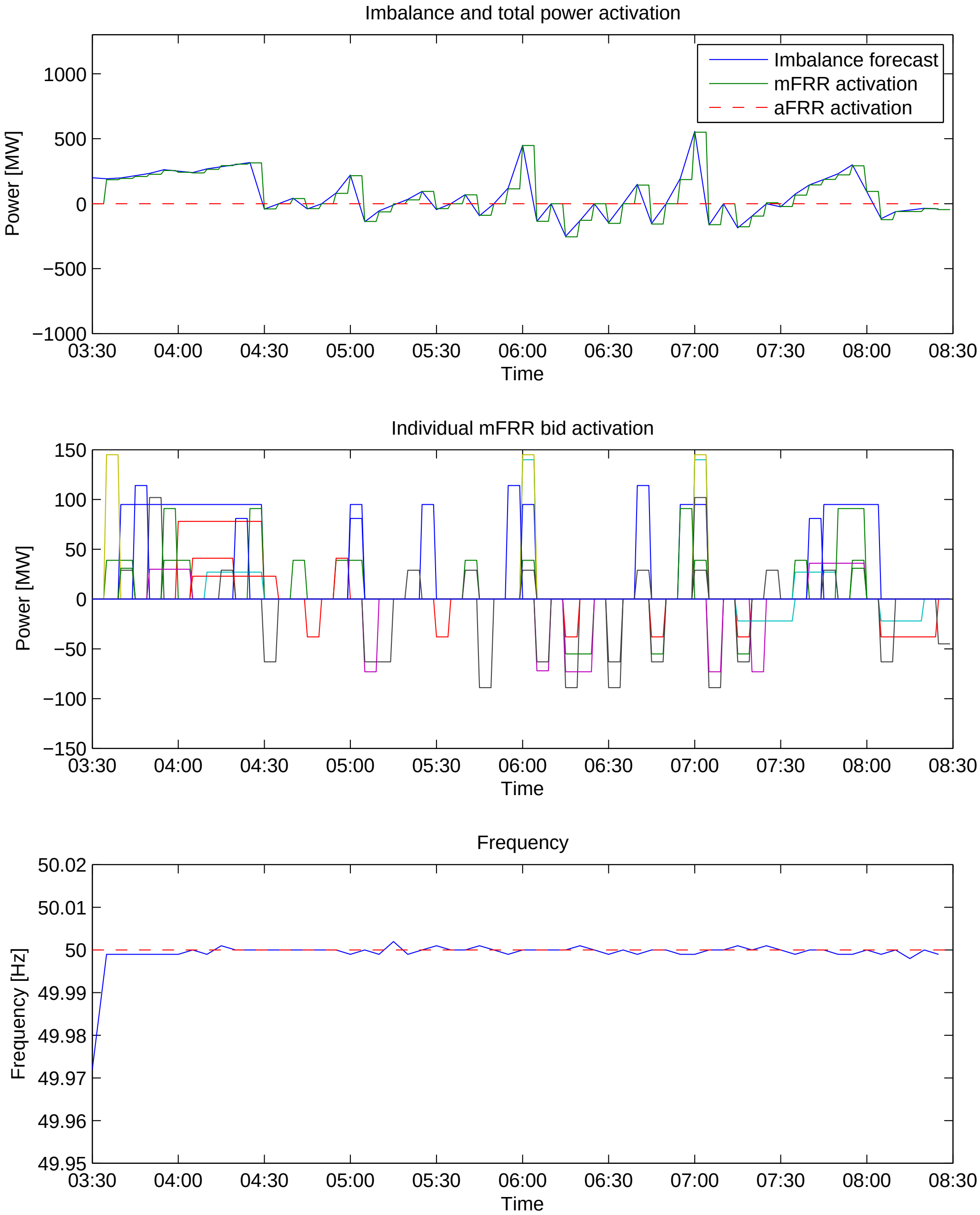


Figure 5.2: Activation of aFRR and mFRR from the Morning Schedule Shifting scenario with zero aFRR capacity.

of using penalty costs in any model is to prevent the model from making unattractive decisions, without making these decisions through a hard constraint. The penalty cost function can thus be seen as a soft constraint. The principle is similar to the one used for penalty function methods, cf. [4, p. 310].

### Setting the Penalty Cost Levels

When not used in a convergence loop, the solution found by the model will to some extent depend on the of the penalty cost parameters. If imposed penalties are very high, they will dominate the costs from activation. Then the model will try to avoid frequency deviations at almost any cost, and the optimal solution will be a solution with the least frequency deviations. If marginal penalty costs are at the level of bid prices or lower, the model will not necessarily restore frequency. The problem of determining the penalty cost parameters is therefore somewhat equivalent to the problem of determining at which bid price should the optimization model should prefer not to cover the imbalance, even if possible.

A short answer is that the added value of providing balancing energy to restore frequency increases with the size of the frequency deviation. This can be achieved by using a non-linear or piecewise linear penalty function. An optimal choice of break points and slope parameters is however, difficult to obtain. For the results in Chapter 4, the penalty cost within 0.1 Hz of $f_N$ is 171 €/MWh, or roughly 5 times the electricity spot price. For deviations outside 0.1 Hz of $f_N$, penalties are about ten times higher. There is a small dead band given by the parameter $\epsilon$ for which no penalty cost incurs, but more importantly, the aFRR implementation acts as a 300 MW (about 0.043 Hz) dead band in each direction in its current formulation (cf. Section 5.2.3).

For the purpose of sensitivity analysis, the Afternoon Base Case and Generator Outage scenarios were re-run with reduced marginal frequency deviation penalties. The penalty term was reduced for the range within 0.1 Hz of $f_N$ by 75%, which gives a marginal penalty of 43 €/MWh, roughly the same level as many of the bid prices for upward regulation. The resulting activation schedules are found in Figs. 5.3 and 5.4. These schedules have fewer activation instructions (6 and 22 vs. 15 and 33) and lower activation costs (16 % and 2 %) for the Base Case and Generator Outage Scenarios, respectively.

It can be argued that the quality of the lower penalty costs solution is not significantly worse from an operations perspective, as the estimated frequency deviations are still within tolerable limits. It is hard to justify the 20 % increase in activation costs for the base case schedule which follows the imbalance profile slightly tighter, especially since it involves a lot more activation instructions. From this perspective, the Lower Penalties solution is better in this case, showing how penalty levels may influence the results. Knowing this, it would have been interesting to see the influence of lower penalty levels on other scenarios as well.

While the original penalty cost level (171 €/MWh for small deviations) instructs the model to avoid frequency deviations whenever possible, the lower penalty level allows a trade-off between frequency quality and economic dispatch, i.e. it is allowed to speculate. Although this may give more attractive solutions and model behaviour, an adequate penalty level may be problem specific and difficult to determine analytically.

It should be noted that these frequency deviation penalty costs are not operational

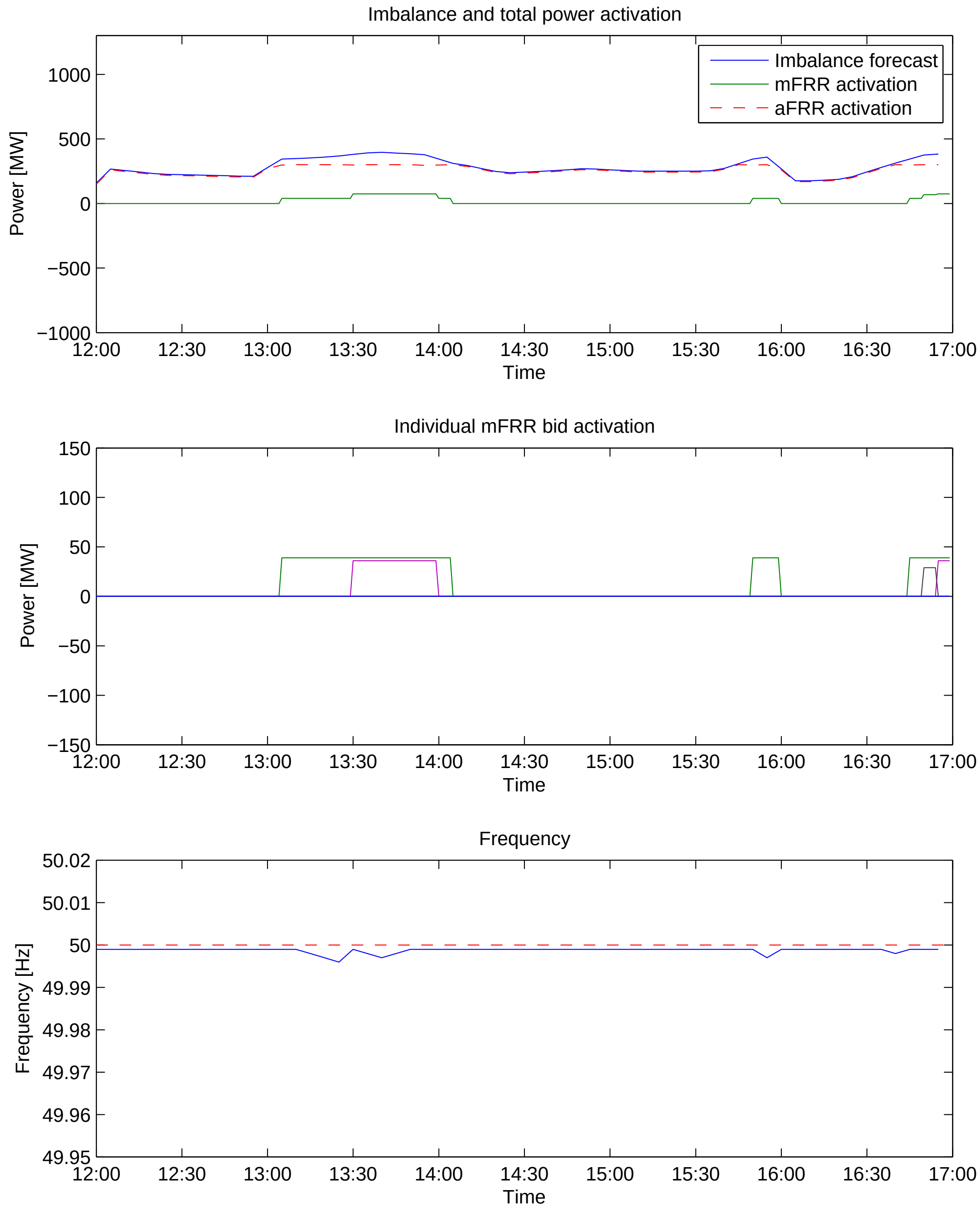


Figure 5.3: Activation of aFRR and mFRR from the Afternoon Base Case scenario with reduced penalty levels.

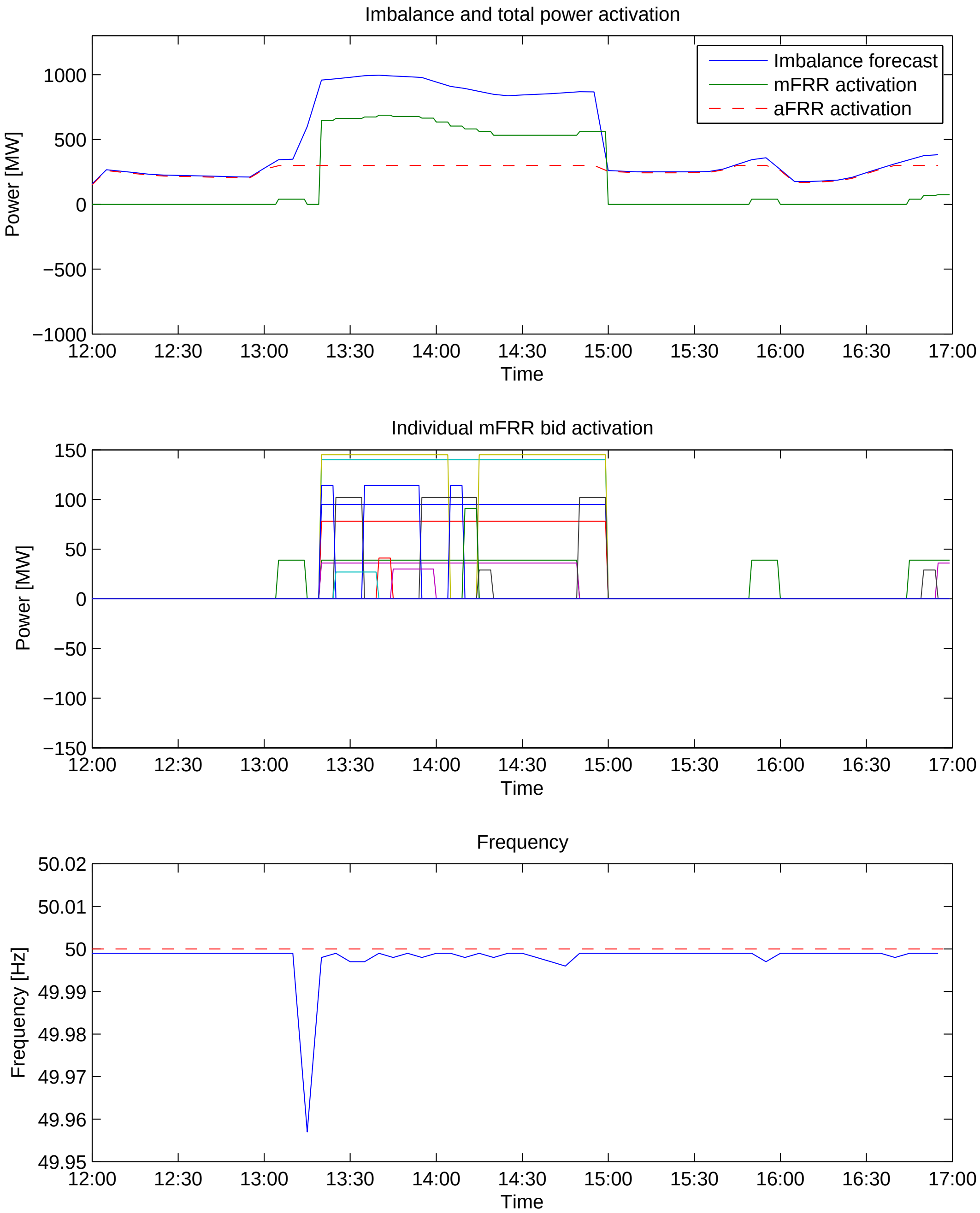


Figure 5.4: Activation of aFRR and mFRR from the Afternoon Generator Outage scenario with reduced penalty levels.

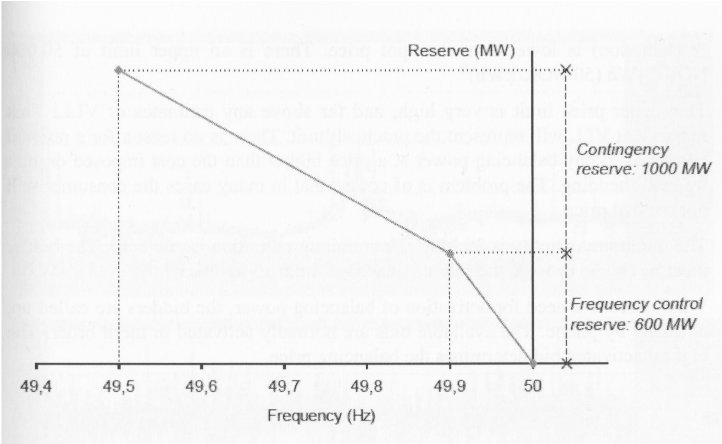


Figure 5.5: The non-linear characteristic of FCR in the Nordic power system [15]

costs or cost to society, but rather an error measure set by the model parameters. This means the penalty costs are generally not comparable to the activation costs, although the model implicitly compares activation costs and penalty costs of different solutions in the search for an optimum.

### The Frequency Deviation Estimate

Penalty costs incur as a function of the estimated frequency deviation for each time step. This estimate is calculated as described in Eq. (3.6), Section 3.2.3. The frequency deviation estimate is found using the current power power imbalance and the frequency bias $\lambda$. This is a simplification for different reasons.

The value of the $\lambda$ is uncertain and depends on time. It is a measure of the amount of power activated from FCR to counteract a frequency deviation. This amount is given by the droop parameter settings on the generators in the system. In Norway, generating units accepted in the FCR-N market must accept a maximum droop setting as instructed by the TSO. Generators may also choose to provide FCR-N even if not accepted in the firm capacity market, in which case they are compensated for their reported contribution [54, p. 2]. This means the amount of FCR-N in the system is not a constant, but may depend on the mix of generating units and their interests, which again depends on the time of day and year, resulting in uncertainty in the $\lambda$ value.

The $\lambda$ characteristic is not linear. The droop settings for FCR-N are used for deviations up to 0.1 Hz in either direction. For larger deviations, the FCR-N is exhausted, and the FCR-D is activated with a different droop characteristic. This is illustrated in Figure 5.5. In addition, controllers have dead bands, meaning the marginal response is not even linear within the first 0.1 Hz of frequency deviation, and the $\lambda$ should be seen as an average value, rather than the actual characteristic of the frequency response. In addition, frequency response is also to some extent dependent on the frequency sensitivity of demand, which is not constant and therefore not known with certainty.

Finally, there are time constants and oscillations related to inertia and control settings in real power systems, meaning the instantaneous frequency will to some extent be coupled in time to previous operation and to the state of a large set of components. Even with the inertia, the system frequency evolves continuously, meaning the 5 minute granularity of the model will filter out very short-term fluctuations.

The frequency deviation estimate is inaccurate for the reasons mentioned above. Although increasing the accuracy of estimates would enable the optimization to find even better solutions, it would not change the principal behaviour of the model. Better frequency deviation estimates could have been obtained with better information and a more sophisticated (e.g. non-linear) calculation.

### 5.2.5 Consecutive Bid Activation

In the optimization model, bids for all Standard Products are assumed to have a flat profile, i.e. they are not allowed to change their power level once fully activated. If the power generated from a bid is to be changed, it would in principle have to be deactivated and reactivated to a new power level in the current model formulation.

While this formulation is simple from a definitions point of view, it is clearly suboptimal in terms of efficient use of resources. A better way to use Standard Products would be to allow bid consecutive bid activation at different power levels, separated by a single ramping period. This would provide additional flexibility without violating any of the physical constraints.

Allowing such behaviour would provide more feasible solutions to the optimization problem, which will generally lead to lower cost schedules. This should be kept in mind when results are analysed.

### 5.2.6 No Network Representation

The balancing energy activation model does not take into account the influence of the transmission network on power balancing. This is a simplification for two main reasons. Firstly, the model assumes no congestions within or between areas, meaning bids from any area is eligible in the activation process without compromising operational security. Secondly, the model does not see how activating a bid affects system losses. Both effects are caused by the fact that changing power injections will alter the flows in the transmission network. This means bids can be attractive or unattractive from a congestion or losses point of view depending on their location.

Norwegian TSO Statnett handle system balancing and congestion management simultaneously using the same bids as for mFRR, but the processes are separated in that activation for congestion management is prioritized and settled using a separate pay-as-bid arrangement [25]. From the balancing perspective, a simplified way to approach this duality in operation is to regard certain bids as unavailable for activation due to their location. As the decisions on availability are made in the congestion management process, the balancing energy activation model can see these as sunk decisions, thus not having to make its own decision on operational security. In this case, the balancing energy optimization model does not need a network structure to make valid decisions on balancing activation.

Activating a balancing bid means changing the net power injection at a node in the power system. Depending on the structure of and flow in the network, the transmission losses will increase or decrease. This means the bid price does not represent the full cost of the activation. The impact on system losses from activating a single bid can be found using power flow calculations, and will generally favour activating bids in net importing areas. Taking this into account in the activation process would require additional calculations using information about the network flow and structure.

At the same time, the framework proposed by ENTSO-E in the Network Code on Load-Frequency Control and Reserves (NC LFC-R) [44] and NC EB [1] and their supporting documents suggests an approach where cross-border exchange does not take marginal losses on interconnections into account. Exploiting the imbalance netting potential and merit order of available bids seems to be more important in the activation methodology proposed in [45]. Whether this approach should also be employed within control areas is to be decided by the member states.

In short, congestion management could be taken into account outside the balancing energy activation model by changing the availability of bids in the market. This is only a modification of the input data, and will only influence the solutions proposed, and not the principal behaviour of the model. Similarly, taking marginal losses into account using power flow calculations could be done outside the model for each of the relevant power injections. The impact of changes in system losses could be included in the objective function of the balancing energy activation model as a part of the cost associated with activating the bid. Once again, this would be equivalent to a modification of bid prices in the input data and would only affect results, and not the principal behaviour of the model. This means taking transmission flow issues into account in balancing activation could perhaps give even more accurate and attractive schedules, but the principal behaviour of the model would remain the same.

Some work has been done on adding a network structure to the balancing energy activation model, based on a transport model methodology using Elspot price areas, as shown in Figure 5.6. The work on the network formulation was postponed and is currently not finished.

### 5.2.7 Simplified Price Levels and Bid Lists

#### Constant Prices Throughout the Horizon

In the Nordic power system, the spot price of electricity is determined for each price area for each hour of the day through the day-ahead wholesale market clearing. Assuming a constant spot price $p^{spot}$ for the entire scheduling horizon of 5 hours is not realistic. Similarly, bids for balancing energy submitted to the RPM may in reality not be available for all hours, and may have different capacities and prices throughout the five-hour period. Assuming the bid list to be constant throughout the period, with no changes in prices or capacities is therefore also a simplification.

While the assumption of constant prices and availability in the RPM is not realistic, it is only a simplification of the data set which decreases complexity in modelling and analysis. The principal behaviour of the model would not change even with a more realistic data set. The results obtained would be more realistic, but at the same time also harder to interpret.

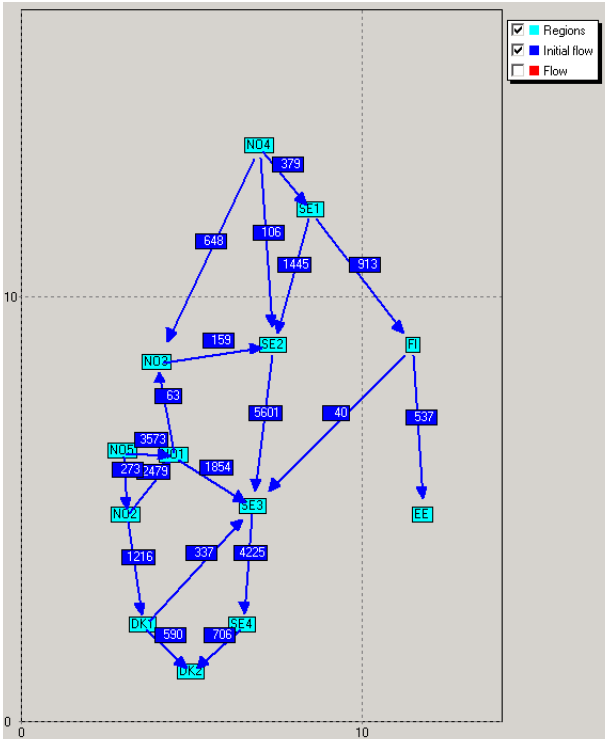


Figure 5.6: Initial cross-area flow used for a case in the transport model balancing energy activation model formulation. Work in progress.

### Price Levels in Bid Lists

The bid lists for upward and downward regulation were created to illustrate the behaviour and preferences of the model with abundant regulating capacity available. As can be seen in Fig. 3.5, hundreds of MW are available for each of the four product types for both upward and downward regulation. The slight differences in price levels of the different products should be noticed. The least expensive bids in both directions are P5 bids, while other product types may start out at significantly more expensive levels (P2 for upward and P4 for downward regulation).

The high representation of P5 bids in duration and number of activation found in the scenario results does not arise solely from the flexibility of the short P5 product, but also from the somewhat non-uniform price levels close to the zero activation point. This biases the optimization model to favour the P5 bids for both small and large imbalances. In comparison, the least expensive P2 upwards bid has a price of 40.1 €/MWh, meaning about 1000 MW of less expensive upwards regulation is available in other products, not including the aFRR.

Bid prices for different products may not necessarily have uniform price levels when CMOLs are introduced in a few years time, and in this regard the composition of the bid list is not unreasonable. On the other hand, the non-uniformity of product price levels to a large extent invalidates comparative analysis of different products. In retrospect, using more uniform price levels or few alternative bid lists would have reduced this bias and given a stronger foundation for conclusions on product design.

### 5.2.8 Other Simplifications and their Influence

As mentioned in Section 5.2.4, the 5 minute granularity of the model means generation and demand are given average values. This gives a static perspective, which especially during hour shifts does not take into account the complexity of operating a dynamic system. In addition, the flexibility of activation is somewhat limited by the requirement of activating bids only on minutes divisible by 5, while direct activated products could in reality be activated at any minute of the hour.

The set of Standard Products chosen from [5] excludes bids P3, P6, P7 and P8. While this exclusion simplifies modelling and analysis, it can be argued that the availability of more product types will increase flexibility in activation. This is especially the case for the extremely flexible P3 product. In fact, the definitions for P3 are so flexible that almost any producer without requirements on minimum duration would be able to provide a bid. Including P3 bids would perhaps give different model behaviour, as this flexibility could have been used for smoothing out small imbalances. Their impact on results would be determined by the energy costs in the bids.

For the Standard Products which have been included, not all product characteristics are taken into account. The maximum duration is set to 120 minutes for all bids, and thus never binding. All bids are considered valid throughout the optimization window. No bids are assumed to have a recovery period between deactivation and re-activation. All bids are assumed divisible (although the indivisibility modelling error allows only full activation of bids, cf. Section 5.3.3). Their location is known, but not used in the current model formulation.

Structural imbalances are handled without the use of schedule shifting. This means a large share of the imbalances are covered using aFRR and mFRR, while in reality, generation schedule shifts could also have been employed during real-time operation to balance the system with lower utilization of the available FRR.

## 5.3 Errors and Influence on Model Behaviour

During analysis, two modelling errors related to bid activation were discovered. Both of these influence the behaviour of the model to some extent. This should be taken into account when discussing the scenario results.

### 5.3.1 Activation Time of Slow Products

There appears to be a small error in the implementation of Eq. (3.18). As a result, all bids, including the slower products, are able to be fully activated within 5 minutes following a re-optimization. For the generator outage scenarios, this will overestimate the capability and flexibility of slower products to some extent, as they would in reality take more time to be fully activated.

### 5.3.2 Coupling of Ramping Bids before Re-Optimization

In a re-optimization, the model takes into account the current commitment status $u_{b,t}$ of a bid, the current generation level $y_{b,t}$ and its current running duration. If a bid is ramping at the time of a re-optimization, its current commitment status is 0, meaning it will be seen as *cold* from a coupling perspective. This coupling could be improved by passing over more unit commitment variables ($u_{b,t+1}$, $u_{b,t+2}$ etc.) in the coupling phase.

### 5.3.3 Indivisibility of Bids

The optimization model strongly favours full capacity activation, and does not use partial activations in any of the activation schedules found in Chapter 4, apart from the Fluid Profile scenario. This influences model behaviour in that all bids are treated as indivisible, significantly constraining the flexibility of the model. As a result, low price bids may be skipped if their full capacity is considered too large, while more expensive bids with lower capacity are activated. A good example is the activation of bid 32, Lillehammer in the Morning Base Case Scenario (cf. Fig. 4.5). Some of the less expensive bids, even shorter and more flexible products are skipped, while this small, more expensive bid is part of the optimal schedule. When bids are in reality considered to be divisible, this schedule is clearly not optimal.

The indivisible scheduling behaviour is due to a modelling error in the ramp rate constraints in Eqs. (3.16) and (3.17). The correct formulations should have been as shown in Eqs. (5.1) and (5.2).

$$y_{b,t} \leq y_{b,t-1} + \overline{y}_b(u_{b,t} - u_{b,t-1}) + \overline{y}_b(1 - u_{b,t}) \qquad \forall b, \forall t \tag{5.1}$$

$$y_{b,t} \geq y_{b,t-1} - \overline{y}_b(u_{b,t-1} - u_{b,t}) - \overline{y}_b(1 - u_{b,t-1}) \quad \forall b, t > T^{start} \tag{5.2}$$

2 The Morning Base Case scenario was run with the corrected ramp rate constraints, now allowing partial activation. No other changes were made. The resulting activation duration of individual bids is showed in Fig. 5.7. The flexibility added allows better utilization of the bids, as their durations now follow the merit order more closely. This also results in a total activation cost of 7 710 € for the 5 hour period, about 4% lower than for the indivisible case. Note that bid 19, Askøy (P2), is still skipped, presumably due to its long minimum duration.

## 5.4 Discussion of Morning Scenarios Results

### 5.4.1 Morning Base Case Scenario

The Morning Base Case Scenario provides an analytical reference for the other Morning scenarios. The activation schedule in Figure 4.1 shows that even with the large imbalances, the optimization schedules an activation of balancing energy which covers the imbalance and provides stable frequency. mFRR is activated and follows the imbalance profile when the aFRR capacity is fully utilized. A further discussion on aFRR activation and margins is found in Section 5.2.3.

Even with the rather large imbalances, the estimated frequency is extremely stable throughout the window. This is partly due to the flexibility of the aFRR, and partly due to the perfect foresight, which is a good approximation in the short term (cf. Section 5.2.1).

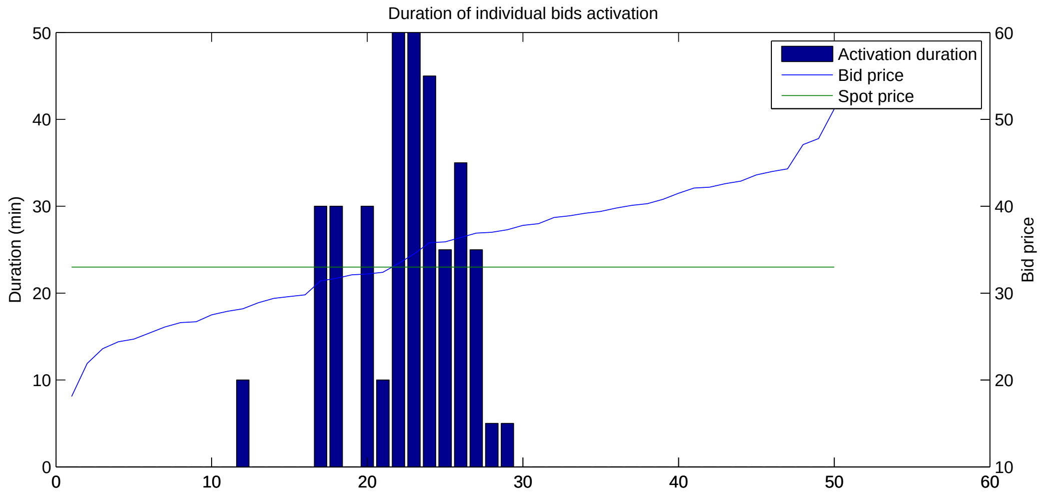


Figure 5.7: Activation duration of individual bids from the Morning Base Case scenario, allowing divisible bids.

As can be seen in Figure 4.5, the duration of the activated bids has similarities to a normal distribution, peaking at bid 22, Lillehammer, which is the least expensive bid for upward regulation. Bid 32, Kristiansund, a low capacity P1 bid which is activated twice, resulting in a total duration of 45 minutes. This is due to the indivisibility modelling error, explained in Section 5.3.3. As the imbalances used in this scenario is to a large extent deterministic, the schedule shifting technique would have been employed during real-time operation.

### 5.4.2 Morning Schedule Smoothing Scenario

Employing the schedule smoothing algorithm to the imbalance forecast reduces imbalance volumes dramatically, in this case to the point where almost all imbalances can be covered using the aFRR capacity alone. Fig. 4.2 shows how the imbalance forecast is now fluctuating around zero as a result of the smoothing. The remaining peaks are significantly reduced, and only 6 mFRR bids are activated to cover what is above the aFRR limit.

All individual activations last for 5 minutes, and the bids chosen are shown in 4.6. As a result of the indivisibility modelling error (cf. Section 5.3.3), these bids are not selected solely on the basis of product and price, but also by their maximum capacity. If bids were divisible, different bids might have been selected.

### 5.4.3 Morning Generator Outage Scenario

The activation schedule for the Morning Generator Outage is shown in Fig. 4.3. The activation schedule is identical to the Morning Base Case schedule until 04:45, when the imbalance is suddenly increased by 600 MW. This results in high imbalance peaks up to about 1200 MW at hour shifts. At this point in time, the aFRR capacity is already fully utilized, and as a result there is no sufficiently fast reserves available to cover the instantaneous imbalance at this time step. The model re-optimizes the schedules using the updated imbalance forecasts, resulting in a high number of immediate activations.

There are inaccuracies in the implementation of coupling through re-optimization, as discussed in Sections 5.3.1 and 5.3.2. The exact size and duration of the post-outage frequency deviation should therefore be regarded only as a very rough estimate. The principal behaviour is easily recognizable, the mFRR activation schedule closely follows the imbalance profile, keeping the estimated frequency deviation within the dead band. The incredibly steep ramp at 06:00 is neither attractive nor feasible due to the limited ramping rate capabilities of real generating units. A better schedule would take this reduced capability into account. This could also be handled through real-time schedule shifting.

The large imbalance volume caused by the combination of structural imbalances and the unexpected outage makes the capacity bias in the indivisibility modelling error (cf. Section 5.3.3) less relevant compared to price and product type. This results in a somewhat normally distributed duration, as can be seen in Fig. 4.20.

### 5.4.4 Morning Schedule Smoothing Generator Outage Scenario

The activation schedule for this scenario is shown in Fig. 4.4. Due to the schedule shifting algorithm, the post-outage imbalance now fluctuates around 600 MW, peaking at about 800 MW. Before the generator outage, there is available aFRR capacity, which is employed to cover parts of the sudden imbalance increase. The mFRR activation covering the remainder of the imbalance is influenced by the modelling weaknesses explained in Sections 5.3.1 and 5.3.2, meaning the validity of the frequency deviation estimate is limited. The energy delivered from ramping should also be taken into account, as explained in Section 5.2.2.

Once again, the mFRR is scheduled to follow the imbalance profile, while a more attractive solution would use aFRR to follow these short-term variations. As discussed in Section 5.2.3, such behaviour will not minimize the objective function, and additional constraints or penalty terms are needed.

The activation duration in Fig. 4.8 shows no bids are activated for downward regulation. This is a result of the schedule smoothing algorithm. As mFRR activation volumes are low compared to the non-smoothing scenario, the maximum bid sizes influence the individual activation duration of bids through the indivisibility modelling error (cf. Section 5.3.3).

### 5.4.5 Comparison of Morning Scenarios

From Table 4.1, it is evident how the schedule smoothing dramatically reduces mFRR activation costs. The lower activation volume and amount of instructions will generally lead to lower prices in the RPM, although this is somewhat obscured by the influence of bid indivisibility (cf. Section 5.3.3), causing expensive bids to be chosen based on their maximum capacity and the influence of high penalty costs. Both these factors may lead to unnecessarily high prices in some cases. Cf. Fig. 5.7 for comparison with a optimization using divisible bids.

Penalty costs are low or non-existent when the optimizer has the opportunity to avoid frequency deviations. The penalty costs in the generator outage scenarios incur from the single time step when the sudden generator outage is introduced.

The shadow price of aFRR capacity shows the improvement of having an extra MW available in each direction. As expected, the added value is larger in the case of a generator outage, in which case the shadow cost is to a large extent determined by the marginal penalty levels.

The final column shows the deterioration of the objective function by limiting the number of activation instructions by 1 compared to what was found in the optimal solution. The extremely low costs indicate that the amount of instructions can be limited without any noticeable impact on total costs. This is interesting, as the optimization model often suggests a large number of activations in the optimal schedule. Perhaps could a roughly cost equivalent activation schedule be obtained using a significantly reduced amount of activations.

From Table 4.2, it is evident how mFRR activation volumes are reduced as a result of the schedule smoothing algorithm. Also aFRR activation is reduced, including a dramatic decrease in the amount of time the aFRR is saturated, i.e. activated to its limit. Together with the significant decrease in mFRR activation, this leads to reduced balancing costs and also provides margins for short-term deviations from the forecast. In principle the reduced volumes will also lead to lower and more predictable imbalance prices, possibly providing better price signals to BRPs.

Tables 4.1 also show the multiplication of activation costs and volumes caused by a large unexpected outage. In reality, the change of power flow in the transmission network could in principle cause congestions, possibly increasing costs even more due to flow limitations (cf. 5.2.6.

Tables 4.3 and 4.4 show the total duration and number of activation instructions for each Standard Product. Very noticeable is the absence of P2 activations in all scenarios. From the definitions in Table 2.2, it is known that P2 is the least flexible of the four products selected for analysis. Still, the persisting upward imbalances, particularly in the generator outage scenarios, have a duration longer than the minimum duration period of the P2 product. One important reason why no P2 bids are activated is the price level bias in the input data (cf. Section 5.2.7. The least expensive upwards P2 bid is Bid 37, Hønefoss, at a price of 40.1 €/MWh. Even though this is a small capacity bid, which tends to be attractive under the indivisibility modelling error (cf. Section 5.3.3), there are 16 bids available for more flexible products at a lower price, and hence it is never activated.

Bids for the P5 product have the highest representation in all Morning scenarios, both in terms of duration and number of activations. The P5 product is able to deliver for 5 minutes, which is also the length of each time step in the optimization, meaning it can alter the power balance in one time step without affect the neighbouring time steps. This is true even with the weak coupling through activation and deactivation times, as ramping energy is disregarded by the model (cf. Section 5.2.2). In addition, the P5 product may deliver power for consecutive periods if necessary.

The P4 product also has a minimum delivery period of 5 minutes, but longer activation and deactivation times than the P5 product. This difference should not be very significant considering most bids in the schedule are up to hours ahead in time. Still, the P5 product has roughly twice the amount of activations and total duration. The main reason for the difference is likely to be the price level bias (cf. Section 5.2.7), causing the model to favour the P5 product simply due to the fact that several low-priced bids exist in the list.

The amount of activations is high, especially in the Morning Generator Outage case, with 47 activation instructions. The low marginal value on the number of allowed activations indicates a possibility that good solutions exists using fewer instructions. It should also be noted that the number of activations in the optimal solution depends on the model parameters, such as the penalty cost levels and the aFRR implementation.

## 5.5 Discussion of Afternoon Scenarios Results

### 5.5.1 Afternoon Base Case Scenario

The activation schedule shown in Fig. 4.9 is found by the balancing energy activation model for the afternoon imbalance forecast. It is optimal under the assumptions and errors discussed in Sections 5.2 and 5.3. This includes maximum utilization of aFRR capacity whenever possible, very small estimated frequency deviations due to penalty cost levels, and indivisible bid activation.

Although the aFRR capacity is sufficient to cover the forecast imbalance throughout most of the scenario, the aFRR will be operating at or close to its upwards limit for almost the entire horizon. The majority of mFRR activation is done between 13:00 and 14:00 when the imbalance is larger than the aFRR capacity limit. Almost all of the activations are small, i.e. less than 50 MW, and they all have durations of 5, 10 and 15 minutes.

The duration statistics in Fig. 4.19 shows the selection and duration of the mFRR bids activated in this scenario. As can be seen, several bids are skipped, while longer bids are allowed to be activated. This is not primarily due to their product types, but a result of the indivisibility modelling error (cf. Section 5.3.3), causing low capacity bids to be preferred in some cases. In this case, the least expensive upwards bid, Bid 22, Lillehammer (P5) is used for only 15 minutes at the imbalance peak around 13:45, while Bid 23, Fredrikstad (also P5) is smaller, and is activated for a duration of 50 minutes, even though more expensive. If bids were treated as divisible, this would clearly not be optimal. Similarly, Bid 42, Gävle (P5) and Borås (P4) are small bids (29 MW and 31 MW), respectively, causing them to be selected for activation in this case.

### 5.5.2 Afternoon Generator Outage Scenario

The activation schedule for this scenario is shown in Fig. 4.10. When the 600 MW generator outage is introduced around 13:15, there is an instantaneous imbalance, causing a frequency deviation. The limited sophistication of the calculation used by the model means it provides only a rough estimate of the size and duration of this frequency deviation. A large amount of mFRR bids are scheduled for immediate activation following the outage. Due to the disregard of ramping energy, the slope of the mFRR power profile in Fig. 4.10 is somewhat unrealistic. In addition, the coupling errors mentioned in Sections 5.3.1 and 5.3.2 influence the schedules proposed by the model.

From 13:15 to 15:00, a large amount of bids are activated and deactivated. This behaviour is cost optimal in the perspective of fully utilizing the aFRR capacity, meaning mFRR bids are scheduled to follow the imbalance profile tightly. From an operations perspective, this schedule is complex and unattractive. The high number of activations also increase the error from the disregard of ramping energy. Nevertheless, some bids are activated for much longer than their minimum duration. Some of them, such as Bid 25, Helsingborg (P4) are activated for more than 90 consecutive minutes. Even with such imbalance durations, no P2 bids are activated due to the price bias (cf. Section 5.2.7).

Although the duration statistics in Fig. 4.20 show a clear tendency of decreasing duration with increasing bid price, the indivisibility modelling error (cf. Section 5.3.3) still impacts the results. Using divisible bids, the model would be able to utilize the lower priced bids to a larger extent, reducing total activation costs. As in the base case, Bids 42 and 44 were used due to their low capacity.

### 5.5.3 Afternoon No P5 Scenario

Throughout the different scenario results, there is a general tendency of a high amount of P5 activations. This is caused by the flexibility of the P5 product and the relatively low price level of P5 bids in the input data. The No P5 Scenario shows how balancing energy is scheduled differently when all P5 bids are removed from the list.

The Afternoon No P5 activation schedule is shown in Fig. 4.11. As with the Afternoon Base Case Scenario, the total mFRR volume is limited. In the No P5 case, fewer bids are activated and the average duration of each activation is longer. The P4 bids are still available, providing 5-minute contributions in four cases.

This activation schedule is clearly influenced by the indivisibility modelling error (cf. Section 5.3.3) and offers a good illustration of its impact on model behaviour. Rather than stacking bids in the merit order using partial activations, the model chooses a series activation of different bids with different capacities to follow the profile of the imbalance forecast. This one-bid-at-each-step behaviour is optimal due to the assumptions and errors made in modelling.

Figure 4.21 shows the duration of the individual bids activated in this scenario. Durations are generally short due to the low activation volume. Most of the skipped bids before Bid 30 for upward regulation are P5 bids, and unavailable for selection. In this case Bid 31, Norrköping (P4) is activated on four occasions, and has the longest duration. This is a result of its low capacity, as two less expensive P4 bids exist (25 and 30). Again, this shows the capacity bias in bid activation caused by the indivisibility modelling error. Together with the low activation volume, there is no clear tendency in Fig. 4.21 of the least expensive resources being used, but rather shows that other factors have larger impact on total cost.

### 5.5.4 Afternoon No P5 Generator Outage Scenario

In the activation schedule in Fig. 4.12, there is a clear tendency of stacking activated bids during the 105 minute outage. The large imbalance volume allows many of the least expensive bids to be fully utilized, while the more expensive bids are only used to follow the profile of the imbalance. This resembles a situation where capacity is divided between base load and peak load. The individual duration of bids, as shown in Fig. 4.22 confirms how bid utilization to a large extent follows the merit order. All skipped bids up before Bid 39 are P5 bids, and even three P2 bids are activated.

Compared to the Afternoon Generator Outage Scenario, in which P5 bids are available, fewer bids are activated, resulting in a higher average bid duration (40 vs. 25 minutes) and higher average energy delivery from each activation (45 vs. 32 MWh). The aFRR activation volume is identical in both scenarios, but, the time saturated is considerably higher At the same time, the aFRR utilization is higher compared to the base case. While not attractive from an operations point of view, from a model perspective this shows that the least expensive resources are being used.

### 5.5.5 Afternoon Some Bids Unavailable Scenario

For this scenario, the least expensive bids are unavailable before 14:00, which results in a different schedule from the Afternoon Base Case. Even though the bids activated are different, the model behaviour is very similar for both scenarios in that they mostly employ small bids, although some of them have high prices. This is a direct result of the indivisible bid behaviour (cf. Section 5.3.3).

The selection of high price bids for this scenario is evident from Fig. 4.23. At the same time, Fig. 4.29 shows the duration of bids before and after the least expensive bids are introduced in the bid list at 14:00. Bid 44, Borås (P4) is activated on four separate occasions and has the longest total duration, even though it has the highest price of all activated bids. Two of the activations even take place after the least expensive bids are introduced, while many of the less expensive bids are skipped. This means the size and product type of these low price bids are less attractive for the optimization, considering the indivisibility of bids and the aFRR implementation.

As expected, activation volumes are almost identical compared to the Afternoon Base Case Scenario. This is also true for the amount of activations and the total duration of bids.

### 5.5.6 Afternoon Some Bids Unavailable Generator Outage Scenario

The activation schedule in Fig. 4.14 shows the minimum cost dispatch subject to the model formulation. During the generator outage, from 13:15 to 15:00, the model schedules a large amount of bids with different capacity and durations. As can be seen directly from the activation schedule, most of the large capacity bids used before 14:00 are replaced at the hour shift when a set of lower priced bids become available.

The duration of individual bids is shown in Fig. 4.24. More informative is perhaps Fig. 4.30, showing the duration of bids before and after the hour shift. At 14:00, 10 different bids are activated for a duration of 35 or 40 minutes, roughly equivalent to the outage duration at this point in time. After 14:00, most of them are barely used, if at all. In the new merit order established after the hour shift, there is sufficient capacity available at lower prices, even with the large imbalance.

Bid 27, Kristiansand (P5, 145 MW) is introduced as a low price bid, but is barely used. It has the largest capacity of all available bids, and the indivisible behaviour (cf. Section 5.3.3) prevents it from being partially activated. Bid 25, Helsingborg (P4, 140 MW) is somewhat similar, but is fully utilized during the remaining outage hour due to its slightly lower price. Activations for Bids 29, Jönköping (P5, 114 MW) and 30, Stavanger (P4, 91 MW) are carried on into the new hour at the 14:00 shift for a short period, and re-activated within the last outage hour.

At the 14:00 hour shift, most of the balancing power is immediately shifted to the newly introduced, lower priced mFRR bids. The result might have been somewhat different if energy delivered from ramping (cf. Section 5.2.2) was taken into account, although the preference of low priced bids would likely persist due to the imbalance volume. Using divisible bids would allow better utilization of the available resources both before and after the 14:00 hour shift, as large low price bids could be used in a versatile way. This would further shift activation volumes towards the low price bids after 14:00 and strengthened the tendency of merit order in bid duration.

### 5.5.7 Afternoon Fluid Profile Scenario

The Afternoon Fluid Profile Scenario is fundamentally different from the previous Afternoon scenarios in that it assumes a completely different bid behaviour. In the Fluid Profile scenario, the ramping constraints in Eqs. (3.16) and (3.17) are disregarded. This not only enables ramping while activated, it also cancels out the indivisibility modelling error (cf. Section 5.3.3), which in other scenarios prevent partial activation of bid capacity.

For the afternoon imbalance with no generator outage, the aFRR provides sufficient balancing capacity most of the time. For the slightly higher imbalance forecast between 13:00 and 14:00, the remaining imbalance not covered by the aFRR is small enough to be covered by a single bid in this case, as shown in Fig. 4.15. Similarly, only one bid is activated for the small peaks before 16:00 and 17:00.

From Fig. 4.25, it is shown that the only bid activated is Bid 22, Lillehammer (P5), which is the least expensive bid available. While the capacity of this bid is sufficient to cover the imbalance at all time steps, the flat profile in constraints in Eqs. (3.16) and (3.17) lead to different solutions in other scenarios using the same imbalance forecast. The aFRR implementation penalty cost levels also influence the solutions found.

The flexibility offered by the fluid profile allows near perfect utilization of the available resources, as balancing power will be increased and decreased in the merit order. This means any less expensive bids should be running at full capacity before a bid is activated. From the perspective of the optimization model, this includes fully activating the aFRR capacity before activating Bid 22, Lillehammer (P5), which is what the model does in this case.

The fluid profile allows the mFRR to fit the imbalance profile perfectly using only the marginal bid. This somewhat resembles the behaviour of the BOA activation used by NG, where instructions are sent in real time to BMUs to change the generation profile. In principle, this mechanism enables imbalance profile following in real-time, and is thus extremely flexible. In reality, the amount of instructions sent is limited to reduce operational complexity. For the schedule in Fig. 4.15, an instruction is sent for each 5 minute time step. These are usually small corrections, and the amount of instructions could be limited without any impact on frequency when not operating at the aFRR limit.

In other scenarios, the model is not able to change the power generation level from bids once they are activated. This is partly due to the erroneous ramping constraints preventing partial activation. Nevertheless, during modelling, the bids were intended to need deactivation and re-activation before allowed to operate at a different power level, i.e. consecutive activations at different power levels would need to stop and start. A more realistic approach would be to allow consecutive activations without deactivation. In such a case, the first minimum delivery period would be followed by a new ramping period before a new minimum duration period is initiated. For the P5 product, which is the most flexible, this would result in the possibility of creating new set points every 10 minutes, providing flexibility similar to what is seen in the Fluid Profile scenario. For slower Standard Products, a similar arrangement would also provide flexibility and facilitate efficient use of resources.

### 5.5.8 Afternoon Fluid Profile Generator Outage Scenario

The activation schedule in Fig. 4.16 supports the findings in the Afternoon Fluid Profile Scenario. During the outage, only one bid is adjusted at a time (with minor exceptions). During the outage before 14:00, Bid 29, Jönköping (P5) is the marginal bid, and continuous adjustment is scheduled to follow the imbalance profile. After 14:00, the forecast imbalance is somewhat smaller, meaning Bid 28, Mo i Rana (P5) will be the marginal bid. This bid is being adjusted throughout the rest of the outage period, including an adjustment at 14:25 to its minimum value, which is assumed to be 1 MW. At this point in time, Bid 27, Kristiansand (P5) is lowered by 3 MW, meaning a decrease at this bid is less expensive than stopping Bid 28, which has a higher marginal cost. This is due to the Standard Product characteristics, as modelled in the constraints.

On a general note, although these characteristics resemble the physical nature of balancing units, they may also introduce constraints which are artificial from a physical point of view, constraining the feasible solution area, resulting in higher cost solutions and less efficient use of resources.

Fig. 4.25 shows the duration of the individual bids used in this scenario. The fluid profiles and possibility of partial activations results in no bids being skipped in order to activate higher priced bids. The duration of bids also decreases with bid price. This utilization of bids indicate that the cost of an activation is determined by the bid price, rather than by the shadow costs on constraints related to Standard Product definitions, as found in [6].

As mentioned for the Afternoon Fluid Profile scenario, allowing continuous adjustments provides flexibility which enables utilizing resources in the order of marginal cost. With a high number of instructions, the flexibility of continuous adjustments conflicts the interest of low operational complexity. As a compromise, consecutive bid activation with different power levels without deactivation should be allowed in the Standard Product definitions, as this would decrease both activation costs and the number of activations.

### 5.5.9 Afternoon Fewer Instructions Scenario

The Afternoon Fewer Instructions Scenario was created to investigate the sensitivity of the total cost of activation schedules on the amount of activation instructions used. From Table 4.5, the marginal value of reducing the number of activation is found to be low (less than 3 % in the first eight scenarios). From [4, p. 115], a constraint on the amount of activations will have more effect the tighter its right hand side coefficient.

In the Afternoon Fewer Instructions Scenario, the optimizer was allowed to schedule no more than 5 mFRR activations over the 5 hour horizon. The resulting activation schedule is found in Fig. 4.17, showing the optimal solution given the formulations in the optimization model. The three bids activated in the period between 13:00 and 14:00 are stacked parts of the time to follow the imbalance profile.

Fig. 4.27 shows which bids are activated and their duration. Due to the indivisibility modelling error (cf. Section 5.3.3), the selection of bids is strongly biased by the maximum capacity of the bids. The bids activated in this scenario are relatively small: Bid 23, Fredrikstad (P5, 39 MW), Bid 24, Moss (P1, 78 MW), Bid 32, Kristiansund (P1, 27 MW), and Bid 38, Lund (P2, 23 MW).

Due to the utilization of aFRR capacity, covering the remainder of the imbalance using five bids is not a capacity issue, but rather an issue of fitting the mFRR activation to the imbalance profile to avoid penalty cost while still utilizing the aFRR capacity. The slightly lower saturation time of aFRR capacity compared to the Afternoon Base Case indicates how the schedule is less able to fit the curve perfectly, reducing the aFRR activation on some time steps and slightly higher penalty costs for frequency deviations.

The activation costs are also slightly higher, although only 3 % compared to the Afternoon Base Case. Total costs (including penalty costs) are 11 % higher using only a third of the amount of activations. The marginal value of the number of activation constraint shows that reducing the amount of activations to 4, rather than 5, would increase the total cost to a level 16 % higher than for the Afternoon Base Case scenario.

### 5.5.10 Afternoon Fewer Instructions Generator Outage Scenario

In the Afternoon Fewer Instructions Generator Outage Scenario the amount of activations was restricted to 9. As this is a scenario involving a re-optization, this limit was obtained by restricting the number of activations after the generator outage to 8. These instructions led to the activation schedule found in Fig. 4.18. Two of the allowed eight activations are used for the small imbalance peaks before 16:00 and 17:00. The remaining six are used to cover the imbalance during the outage between 13:15 and 15:00.

Compared to all other generator outage activation schedules, the mFRR schedule does not provide a tight fit to the imbalance forecast profile, even though this usually gives minimum cost from the model perspective. A tight fit would require more activations or fluid profiles. In this case, the mFRR power generation level is only changed once during the outage, at 14:15, leaving it to the aFRR to provide the fitting to the imbalance profile.

Using aFRR for imbalance fitting, rather than fully utilizing its capacity, is generally suboptimal in the current aFRR implementation. From a model perspective, it must be seen as an emergency solution, even though using aFRR for smoothing in reality is the most reasonable thing to do due to uncertainty in forecasts.

From the duration statistics in Fig. 4.28, 5 bids are activated for about 100 minutes each, while Bid 23, Fredrikstad (P5, 39 MW) is only activated for a short time before the outage. Bid 29, Jönköping is activated for about 50 minutes during the first half of the outage. Bid 26, Tromsø (P1, 36 MW) is skipped in the list. Its small capacity is unattractive when covering a large imbalance with a limited amount of activations.

Reducing the amount of activations to the point where bids are skipped due to their size is bad operational design and clearly inefficient. Still, the costs are not significantly higher in this case. Activation cost are less than 2 % higher than in the Afternoon Generator Outage scenario. Total costs are 3 % higher. Reducing the total amount of activations to 8 gives 5 % higher costs. Compared to the 33 activation instructions in the Afternoon Generator Outage scenario, it shows how the model may find very different solutions which are approximately cost equivalent. It also illustrates the small significance on costs of the high amount of corrective or adjusting activations proposed by the model, the value of which are also very questionable from an operations point of view.

It should be added that the model would provide better solutions for all scenarios if partial activation was not disallowed by the indivisibility modelling error (cf. Section 5.3.3).

### 5.5.11 Comparison of Afternoon Scenarios

While the activation schedules and bid duration has been discussed in the previous sections, this section focuses on the findings in Tables 4.5 to 4.8.

#### Cost Results

Table 4.5 shows mFRR activation costs, penalty costs and the dual values of constraints on aFRR capacity and number of activations.

The exact numbers found in the table is influenced by the assumptions and systematic errors made in the model, as well as the selection of model parameter values. Therefore, more interesting than the numbers themselves, are the the tendencies and relations between the results in the different scenarios.

For the non-outage scenarios, the activation costs are lowest in the Fluid Profile scenario. This is no surprise, as this scenario has the least amount of constraints, including allowing partial activation. This scenario demonstrates the value of flexibility, as this enables full utilization of the least expensive resources. For the flat profile scenarios, the Base Case scenario has the least constraints, giving the lowest total cost, and in this case also the lowest activation cost. The somewhat higher activation cost in the No P5 and Bids Unav. scenarios are caused by the differences in the input data sets, but from an optimization point of view this is equivalent to an extra set of constraints on the relevant bids. The Fewer Instruction scenario also has higher activation costs than the Base Case, but the cost difference is small considering the difference in the amount of activations.

For the outage scenarios, differences in activation costs are larger in absolute numbers, but still relatively small when compared to each other. The near-perfect resource utilization in the Fluid Profile scenario only manages to reduce activation costs by 1.5 % compared to the Base Case, while the three other outage scenarios have activation costs less than 5 % higher than the Base Case.

The penalty costs quantify the estimated frequency deviations for the optimal schedules for each of the scenarios. For the non-outage scenarios, the penalty costs are generally low compared to the activation cost, indicating that the sum of mFRR and aFRR schedules follows the imbalance forecast closely. The small penalty cost (e.g. 157 € for the Afternoon Base Case scenario), incurs from the microscopic frequency dip around 16:40 for the first three non-outage scenarios. The Fluid Profile schedule is sufficiently flexible to prevent frequency deviations, while a few more small frequency deviations in the Fewer

Instructions schedule leads to slightly higher penalty costs.

Regardless of the differences in penalty costs, the estimated frequency deviations are negligible in all of the non-outage schedules. In reality, random variations, forecast errors, power system dynamics and noise would all be likely to have larger impact on frequency. This raises the question of how much could be saved by allowing the model to perform slightly worse in terms of frequency without imposing a large penalty on the objective function, as was discussed in Section 5.2.4.

The aFRR shadow price is found using two separate optimization runs with different aFRR capacity limits. This approach is necessary due to the integer nature of the problem, but may lead to a different basic feasible solution being selected. The separate optimization runs introduce uncertainty into the calculation of these dual values through numerical issues such as convergence gaps. The results generally indicate a shadow price in the size of 100 €/MW for the 5 hour horizon. This value is closely related to the activation cost of the energy which would not have been covered by mFRR given additional aFRR capacity. In principle this is the sum of marginal cost of operation throughout the horizon, but the calculation is obscured by the indivisibility of bids (cf. Section 5.3.3).

Similarly, the dual value of the activation amount constraint was found using two separate optimization runs for each scenario, and therefore is subject to the same uncertainty. For the first three non-outage scenarios, the reduced value of removing a constraint is negligible. For the Fluid Profile scenario, the number of activations is already very low, but decreasing it from 3 to 2 still does not have any major impact on the activation cost. The dual values are significantly higher in the Fewer Instructions scenarios, both for the non-outage and outage case, as the ability to follow the imbalance profile using mFRR is already very limited. For the other outage cases, reducing the total activations by 1 has a negligible impact on total costs, which is not surprising considering the relatively low cost of the Fewer Instr. Generator Outage schedule.

### Volumes and Product Preferences

Table 4.6 shows the activation volumes for the different scenarios. In addition, it shows the amount of time the aFRR is operating at the limit of its capacity, i.e. +300 MW for these scenarios.

The activation volumes are to a large extent given simply by the forecast imbalance volume. Therefore, mFRR volumes are roughly equal in all scenarios. The lowest mFRR volumes are found in the Fluid Profile scenarios, in which the flexibility allows the optimizer never to activate more power than necessary. On the other side, the additional constraint on number of activations in the Fewer Instructions scenarios lead to slightly higher volumes. No downward mFRR is scheduled to be activated, as the imbalance forecast stays positive for the entire optimization window.

The aFRR volumes are almost identical in all non-outage cases, apart from the Fewer Instructions scenario, in which the frequency is scheduled to be at the upper, rather than at its lower band most of the time. This is still cost optimal, as using aFRR imposes no cost in the objective function. For the outage scenarios, aFRR volumes are essentially identical.

The aFRR saturation is interesting from a model perspective, because it indicates the ability of the solution to follow the imbalance profile using mFRR bids while fully utilizing the aFRR. High aFRR utilization thus indicates flexible mFRR behaviour. Noticeable is the high saturation times of the Fewer Instructions scenarios. At the same time, the aFRR behaviour is very similar in all scenarios, and the saturation status is sometimes arbitrary due to the frequency penalty dead band.

Tables 4.7 and 4.8 show the total duration and number of activations for each of the four Standard Products used by the model. The preferences of the optimization model is biased by the indivisible bid behaviour favouring small bids in some cases, the different price levels of different products, and the flexibility provided by the product characteristics themselves.

As can be seen from the Base Case and Generator Outage scenarios, the optimization strongly favours the P5 product, both in terms of duration and total number of activations. This is in part caused by the relatively low price level of P5 bids in the bid list. Similarly, P2 bids are rarely activated, in part because of their long minimum duration, but also due to their relatively high bid price level.

The total number of activations for a schedule can be seen as a measure of its operational complexity. Schedules with a high number of activations are often able to follow the imbalance profile closely, often leading to optimal solutions from a model perspective. The total duration, on the other hand, is rather a measure on the degree of simultaneous activation, i.e. to which extent the imbalance is covered using a series of large capacity bids or a stack of lower capacity bids.

The extreme case is the Afternoon Fluid Profile scenario, where Bid 22, Lillehammer (P5) is the only bid to be activated. All other non-outage scenarios have higher total duration, indicating different bids are overlapping at some points, c.f. the Fewer Instructions scenario. For the generator outage scenarios there are large differences in the number of activations, compared to which the differences in total duration are small. This means there are large differences in the average duration each activation, from 21 minutes in the Some Bids Unavailable scenario to 66 minutes in the Fewer instructions scenario.

The differences in duration and activations describe how different constraints and changes in input data influences the model, as they outline what an attractive solution looks like in each of the cases. Still, it should be kept in mind that these outlines may be different if model parameters or implementations are adjusted.

## 5.6 Retrospective Comments

As mentioned throughout Sections 5.4 and 5.5, the results are influenced by the simplifications and errors made in modelling. In some cases, the choices of the model seem irrational, while in reality perfectly rational using the wrong set of rules.

Many of these issues have been addressed and optimizations have been re-run. The new schedules are more flexible, have lower cost and shorter running times compared to what is presented in the results in Chapter 4. In short, the optimization model shows great promise, even though the results presented in this thesis do not present its full potential.

## 5.7 Impact and Relevance on European Policy

The design of the Standard Products and Activation Optimization Function is essential to efficient cross-border exchange of balancing services. As the Standard Product definitions are passed on as constraints in the optimization, effort should be made to ensure they provide the flexibility needed to balance the system in the most efficient manner. For a proactive balancing approach, allowing fluid profiles has been shown to enable near-perfect resource utilization. Allowing consecutive bid activations at different power levels would provide much of the same flexibility with a lower amount of restrictions. Optimal schedules have been found to deviate from merit order if non-flexible formulations, such as indivisible bids, are imposed. This illustrates the sometimes significant shadow costs imposed by the constraints in optimization.

For the proposed products, the amount of energy delivered during activation and deactivation may in some cases be similar to the amount of energy delivered during the fully activated period. Disregarding this energy in optimization may potentially lead to unattractive schedules and large volume errors. At the same time, simply using the ramping profile specified in the Standard Product characteristics will also lead to errors. Requiring bid providers to follow this schedule is suboptimal in terms of resource efficiency, but will reduce volume errors and improve controllability of the system.

Though the use of an Activation Optimization Function, as proposed in [1], will facilitate cross-border exchange of balancing services, the efficiency of its solutions will depend on its level of sophistication. A sophisticated algorithm would enable efficient use of resources while taking operational security into account. The results demonstrating the balancing energy activation model developed for this thesis show the impact of different assumptions and simplifications in the optimization, in some cases providing examples of how bad solutions can be optimal if the model is not sufficiently sophisticated.

## 5.8 Future Work and Improvements

As mentioned in Section 5.6, the results provided do not represent the full potential of the balancing energy activation model. Although some of these issues concerning assumptions and errors have already been addressed, development of the model will continue during the next months. Particular attention will be given to the issues within the balancing energy activation model already mentioned in the discussion. Further on, other aspects of activation optimization will be analysed. This may include extending or branching the activation model in some cases. Among the topics of interest are:

**The aFRR implementation** has a major influence the model behaviour and causes unattractive optimal solutions. In the future, different approaches will be implemented and tested.

**Physical profiles** including energy from ramping will be formulated and tested. Such profiles may better estimate the volume delivered by a bid, reducing errors and uncertainty in frequency deviation estimates.

**Consecutive Bid Activation** will be allowed in the future formulations. This will be compared to the current formulation and the fluid profiles used in the Fluid Profile scenario to determine the amount of flexibility provided.

**A network implementation** could provide a new framework for analysis of different activation optimization formulations and scenarios. The network model and the activation optimization algorithm could be built in separate modules and combined in e.g. a simulation program.

**A forecasting algorithm** for imbalances could be developed using time series models or different mathematical techniques. This could be used to investigate the uncertainty and dynamic behaviour of real imbalances.

**Alternative activation algorithms** for Standard Products for balancing energy. This would likely include stochastic and heuristic approaches.

# Chapter 6

# Conclusion

For the purpose of this thesis, an optimization model for balancing energy was developed. This model uses an imbalance forecast to find an optimal activation schedule for frequency restoration reserves from the bids available in the market. The schedule found by the model will be optimal subject to the assumptions and simplifications made in the model, although not always favourable from an operations perspective.

A fictive list of bids for upward and downward regulation was created and coupled with some of the Standard Product definitions proposed by ENTSO-E Working Group Ancillary Services [5]. These bids were used together with real imbalance forecasts from Norway to investigate the activation of balancing energy using Standard Products. Scenarios were created to look into different aspects of activation and the balancing process, emphasizing on covering structural imbalances and an unexpected generator outage.

The seemingly irrational decisions made by the optimization model in some scenarios were identified to be influenced by simplifications, parameter choices and a modelling error preventing partial bid activation. In short, the validity of the results presented in this thesis is limited, somewhat obscuring the observations on the use of Standard Products for electricity balancing. Resolving some of the modelling issues have been found to increase the quality of solutions found by the model.

In several of the scenarios, the optimal activation schedules involved a high amount of short activations. This behaviour is sensitive to the frequency deviation penalty levels and the flexibility of bid and product definitions. When reducing the amount of activations using a constraint, the impact on costs was found to be very low. However, as for the penalty levels, there is no straightforward way to determine an appropriate or universal value.

The scenarios using fluid profiles, i.e. allowing ramping during the delivery period of bids, illustrate very well how flexible product design enables efficient use of resources. When sufficiently flexible, the optimization model chooses a merit order activation of bids, indicating that the bid price itself comprises the major part of the cost of activating the bid. Although using fluid profiles would be complex from an operations point of view, allowing consecutive bid activation without deactivation would, to a certain extent, provide the same kind of flexibility.

To obtain efficient use of balancing resources, balancing markets must not only be integrated and harmonized, effort should also be made in the design of Standard Products to avoid characteristics causing inflexibility unless strictly necessary.

Finally, it should be kept in mind that with the deterministic approach used, the optimization does take uncertainty into account. No costs incurs, unless explicitly stated, from decisions which in reality would introduce risk.

# Appendix A

# Xpress Model Implementation

## A.1 Initializations and Declarations

```
model SecondGenModel
uses "mmxprs";
uses "mmodbc";

parameters
Print = TRUE
AFRR = TRUE
Stage = 2
Scenario = "outage"
!DataFile = "mmodbc.odbc:balancingDataStruct.xlsx"
!DataFile = "mmodbc.odbc:balancingDataHS.xlsx"
DataFile = "mmodbc.odbc:balancingDataHSsbu.xlsx"
!DataFile = "mmodbc.odbc:balancingDataHSNoP5.xlsx"
!DataFile = "mmodbc.odbc:balancingDataSmooth.xlsx"
Prefix = "ASBU"
end-parameters

declarations
Stages: set of integer
STAGESTARTTIMES: array(Stages) of integer
TIMEPARAMS: array(1..3) of integer
Time: set of integer
TimeInterval: set of integer
Horizon: set of integer
nTime: integer
loTime: integer
HOURSHIFT: integer
StageTime: array(Stages) of set of integer
end-declarations


initializations from DataFile
STAGESTARTTIMES as 'StageStartTimeRange'
TIMEPARAMS as 'TimeParamRange'
end-initializations


StartTime := STAGESTARTTIMES(Stage)
if (Stage < getsize(Stages)) then
NextStage := STAGESTARTTIMES(Stage+1)
end-if

nTime := TIMEPARAMS(1)
loTime := TIMEPARAMS(2)
HOURSHIFT := TIMEPARAMS(3)

forall(s in Stages | s <> 4) StageTime(s) := STAGESTARTTIMES(s)..(STAGESTARTTIMES(s+1)-1)
```

```
forall(s in Stages | s = 4) StageTime(s) := STAGESTARTTIMES(s)..nTime


if (Stage = 1) then
InitialConditions := 'OutageInitZero.dat'
else
InitialConditions := Prefix + "Stage" + string(Stage-1)+".dat"
end-if


Time := StartTime..nTime
Horizon := 1..nTime
TimeInterval := 1..loTime

forward procedure matlab
forward procedure stageshiftoutput

declarations
Bids: set of string
BidsUp: set of string
BidsDn: set of string
Prods: set of string
FrequencyControlBias = 7000
AFRRLOWER = -300
AFRRUPPER = 300
HIGHDEV = 200
LOWDEV = -200
OUTDEV = 600
PenaltySplit  = 0.1
DeadBand   = 0.001
PenaltyPart1  = 100000
PenaltyPart2  = 1000000
MaxInstr = 100
end-declarations




declarations

REALIMB: array(Time) of integer
PRICE:  real
BIDCAP:  array(Bids) of integer
BIDPRICE: array(Bids) of real
BIDMAXDP: array(Bids) of integer
BIDREGION: array(Bids) of string
BIDPTYPE: array(Bids) of string
BIDAVHR1: array(Bids) of boolean
BIDAVHR2: array(Bids) of boolean
PRODFAT: array(Prods) of integer
PRODDT: array(Prods) of integer
PRODMINDP: array(Prods) of integer

! Initial bid status
INITACT: array(Bids) of integer
INITGEN: array(Bids) of real
INITDUR: array(Bids) of integer

! Decision variables
activated: array(Bids,Time) of mpvar
generation: array(Bids,Time) of mpvar
afrr: array(Time) of mpvar
start: array(Bids,Time) of mpvar

! Frequency calculation and control
Frequency: array(Time) of linctr ! System frequency after AGC
FrequencyUnder1: array(Time) of mpvar ! First step of piecewise linear penalty function
FrequencyUnder2: array(Time) of mpvar ! Second step of piecewise linear penalty function
FrequencyOver1: array(Time) of mpvar ! First step of piecewise linear penalty function
FrequencyOver2: array(Time) of mpvar ! Second step of piecewise linear penalty function
```

```
OverFrequency1: array(Time) of linctr ! Calculating freq dev values over
OverFrequency2: array(Time) of linctr ! Calculating freq dev values over
UnderFrequency1: array(Time) of linctr ! Calculating freq dev values under
UnderFrequency2: array(Time) of linctr ! Calculating freq dev values under


TotalCost: linctr
DemandCon: array(Time) of linctr
CapCon: array(Bids,Time) of linctr
MinLevel: array(Bids,Time) of linctr
BidMaxDur: array(Bids) of linctr
StartupDelay: dynamic array(Bids,Time) of linctr
ProdMinDur: array(Bids, Time) of linctr
MaxUpRampRate: array(Bids, Time) of linctr
MaxDnRampRate: array(Bids, Time) of linctr
Downtime: array(Bids, Time) of linctr
Unavailable: array(Bids, Time)  of linctr
MaxAFRR: array(Time) of linctr
MinAFRR: array(Time) of linctr
Uptime: array(Bids, Time) of integer
TimeLeft: array(Bids) of integer
MaxInstructions: linctr
StartUpSetter: array(Bids, Time) of linctr
StartTight: array(Bids, Time) of linctr

! Stage II initial conditions
InitOperation: array(Bids) of linctr
InitGeneration: array(Bids) of linctr

! RESULTS: stage cost components
StageActCost: array(Stages) of linctr
StageFDCost: array(Stages) of linctr
end-declarations




initializations from DataFile
PRICE as 'PriceRange'
[BIDCAP,BIDPRICE,BIDMAXDP,BIDREGION, BIDPTYPE, BIDAVHR1, BIDAVHR2] as 'BidRange'
[PRODFAT,PRODDT,PRODMINDP] as 'ProductRange'
end-initializations

forall(b in Bids) do
INITACT(b) := 0
INITGEN(b) := 0
INITDUR(b) := 0
end-do


if (Stage = 1) then
initializations from DataFile
REALIMB as 'ImbalanceRange'
end-initializations
elif (Stage = 2) then
initializations from DataFile
REALIMB as 'ImbStage2Range'
end-initializations
elif (Stage = 3) then
initializations from DataFile
REALIMB as 'ImbStage3Range'
end-initializations
elif (Stage = 4) then
initializations from DataFile
REALIMB as 'ImbStage4Range'
end-initializations
end-if


if (Scenario = "high") then
```

```
forall(t in Time) REALIMB(t) := REALIMB(t) - HIGHDEV
elif(Scenario = "low") then
forall(t in Time) REALIMB(t) := REALIMB(t) - LOWDEV
elif(Scenario = "outage") then
forall(t in Time | t < HOURSHIFT+12) REALIMB(t) := REALIMB(t) - OUTDEV
end-if



! Split bid list
forall(b in Bids | BIDPRICE(b) > PRICE) BidsUp += {b}
BidsDn:= Bids - BidsUp
```

## A.2 Objective Function and Constraints

```
! COST CALCULATIONS
ActivationCost := sum(b in BidsUp, t in Time) generation(b,t)*BIDPRICE(b)*loTime/60 +
sum(b in BidsDn, t in Time) generation(b,t)*(PRICE-BIDPRICE(b))*loTime/60
FreqDevCost :=  sum(t in Time) (PenaltyPart2*(FrequencyOver2(t) + FrequencyUnder2(t))) +
sum(t in Time)(PenaltyPart1*(FrequencyOver1(t) + FrequencyUnder1(t)))
TotalCost := ActivationCost + FreqDevCost

! System frequency and deviation calculations
forall(t in Time) do
Frequency(t) := 50 + ((sum(b in BidsUp) generation(b,t)-
(sum(b in BidsDn) generation(b,t))) + afrr(t) + REALIMB(t))/FrequencyControlBias
OverFrequency1(t) := FrequencyOver1(t) <= PenaltySplit - DeadBand
OverFrequency2(t) := FrequencyOver2(t) >= Frequency(t)-(50 + DeadBand + FrequencyOver1(t))
UnderFrequency1(t) := FrequencyUnder1(t) <= PenaltySplit - DeadBand
UnderFrequency2(t) := FrequencyUnder2(t) >= (50-DeadBand - FrequencyUnder1(t))-Frequency(t)
end-do

! BID specification constraints
! Max capacity constraint
forall(b in Bids, t in Time) CapCon(b,t) := generation(b,t) <= BIDCAP(b)*activated(b,t)
! Minimum level constraint
forall(b in Bids, t in Time) MinLevel(b,t) := activated(b,t) <= generation(b,t)
! Bid max duration constraint
forall(b in Bids) BidMaxDur(b) := sum(t in Time) activated(b,t) <= BIDMAXDP(b)/loTime

! PRODUCT specification constraints

! Activation time requirement
forall(b in Bids, p in Prods | BIDPTYPE(b) = p) do
forall(t in Time | t < PRODFAT(p)/loTime + 1) do
create(StartupDelay(b,t))
StartupDelay(b,t) := activated(b,t) = 0
end-do
end-do

! Reformulated minimum duration requirement
forall(p in Prods, b in Bids | BIDPTYPE(b) = p) do
! Zendehdel 14a
if(INITACT(b) = 1 and INITDUR(b)<(PRODMINDP(p)/loTime)) then
TimeLeft(b) := round(PRODMINDP(p)/loTime)-INITDUR(b)+1
writeln(b, ",", TimeLeft(b))
ProdMinDur(b,StartTime) := sum(t in StartTime..StartTime+TimeLeft(b)) activated(b,t) = TimeLeft(b)
else
TimeLeft(b) := 0
end-if
! Zendehdel 14b
forall(k in StartTime + TimeLeft(b) +1 .. nTime - round(PRODMINDP(p)/loTime) + 1) do
ProdMinDur(b,k) := sum(t in k .. k+round(PRODMINDP(p)/loTime)-1) activated(b,t) >=
round(PRODMINDP(p)/loTime)*(activated(b,k) - activated(b,k-1))
end-do
! Zendehdel 14b
```

```
forall(k in nTime - round(PRODMINDP(p)/loTime) + 2 .. nTime) do
ProdMinDur(b,k) := sum(t in k .. nTime) activated(b,t) >= sum(t in k .. nTime) (activated(b,k)-activated(b,k-1))
end-do
end-do

! No ramping while fully activated
forall(b in Bids, t in Time | t > StartTime) do
MaxUpRampRate(b,t) := generation(b,t) <= generation(b,t-1) + BIDCAP(b)*(activated(b,t)-activated(b,t-1))
!+ BIDCAP(b)*(1-activated(b,t))
MaxDnRampRate(b,t) := generation(b,t) >= generation(b,t-1) - BIDCAP(b)*(activated(b,t-1)-activated(b,t))
!- BIDCAP(b)*(1-activated(b,t-1))
end-do


! Time interval before new activation
forall(p in Prods, b in Bids, t in Time | BIDPTYPE(b) = p and t > StartTime + round((PRODFAT(p)+PRODDT(p))/loTime)) do
!writeln("b: ", b, ", t: ", t)
Downtime(b,t) := activated(b,t) <= 10*activated(b,t-1) + 1 - 0.1*sum(i in 1..round((PRODFAT(p)+PRODDT(p))/loTime)) activated
end-do


forall(b in Bids, t in Time |(t < HOURSHIFT and BIDAVHR1(b) = FALSE)) Unavailable(b,t) := activated(b,t) <= 0
forall(b in Bids, t in Time | (t > HOURSHIFT-1 and BIDAVHR2(b) = FALSE)) Unavailable(b,t) := activated(b,t) <= 0

! Binary requirements
forall(b in Bids, t in Time) activated(b,t) is_binary
!forall(b in Bids, t in Time) activated(b,t) <= 1

forall(t in Time) afrr(t) is_free
if (AFRR = FALSE) then
forall(t in Time) afrr(t) = 0
end-if

! aFRR limits
forall(t in Time) do
MaxAFRR(t) := afrr(t) <= AFRRUPPER
MinAFRR(t) := afrr(t) >= AFRRLOWER
end-do

! Set start ups for counting
forall(b in Bids, t in Time | t > StartTime) StartUpSetter(b,t) := start(b,t) >= activated(b,t) - activated(b,t-1)
forall(b in Bids, t in Time) start(b,t) <= activated(b,t)
forall(b in Bids, t in Time| t > StartTime) start(b,t) <= 1-activated(b,t-1)



! Initializations
forall(b in Bids) do
InitOperation(b) := activated(b,StartTime) = INITACT(b)
InitGeneration(b) := generation(b,StartTime) = INITGEN(b)
end-do

! Max instructions
MaxInstructions := sum(b in Bids, t in Time) start(b,t) <= MaxInstr
```

## A.3 Results Management

```
if (Print) then
setparam('xprs_verbose',true);
setparam('xprs_miplog',-2500);
end-if

minimize(TotalCost)

matlab ! Write solution data to Matlab file
```

```
writeln
writeln("Total starts: ", sum(b in Bids, t in Time | (t > StartTime and
getsol(generation(b,t)) > 0.1)) getsol(start(b,t)))
writeln

forall(b in Bids,t in Time) do
if (getsol(activated(b,t)) > 0.1) then
writeln("Bid ", b, " activated: Running (", getsol(activated(b,t))," ) at ", getsol(generation(b,t)), " at time ", t)
end-if
end-do
writeln

(!
forall(b in Bids,t in Time) do
if (getsol(start(b,t)) > 0.1) then
writeln("Bid ", b, " started (", getsol(start(b,t))," : at ", getsol(generation(b,t)), " at time ", t)
end-if
end-do
!)

writeln("\nObj. value: ", getobjval)
writeln("\nActivation costs: ", getsol(ActivationCost))
writeln("Penalty costs: ", getsol(FreqDevCost))
writeln
!  COST elements
forall(s in Stages | s >= Stage) do
StageActCost(s) := sum(b in BidsUp, t in StageTime(s)) getsol(generation(b,t))*BIDPRICE(b)*loTime/60 +
sum(b in BidsDn, t in StageTime(s)) getsol(generation(b,t))*(PRICE-BIDPRICE(b))*loTime/60
StageFDCost(s) := sum(t in StageTime(s)) (PenaltyPart2*(getsol(FrequencyOver2(t)) + getsol(FrequencyUnder2(t)))) +
sum(t in StageTime(s))(PenaltyPart1*(getsol(FrequencyOver1(t)) + getsol(FrequencyUnder1(t))))
writeln("Stage ", s, ": ", strfmt(getsol(StageActCost(s)),10,1), strfmt(getsol(StageFDCost(s)),10,1))
end-do


! RUNCOUNTS

forall(b in Bids) do
Uptime(b,StartTime) := INITDUR(b)
forall(t in Time | t > StartTime) do
if (getsol(activated(b,t)) = 0) then
Uptime(b,t) := 0
else
Uptime(b,t) := Uptime(b,t-1) + 1
end-if
end-do
end-do


if (Stage <> 4) then
stageshiftoutput
end-if




!----------------------------------PROCEDURE IMPLEMENTATIONS---------------------------------
! Generate Matlab file
procedure matlab
SolFileName := "SolutionFileR" + Prefix+string(Stage)+".m"
fopen(SolFileName,F_OUTPUT)

writeln("PowerActivated = [")
forall(t in Time,tt in TimeInterval | t < nTime) do
forall(b in BidsDn) write(strfmt(-getsol(generation(b,t)),5,0))
forall(b in BidsUp) write(strfmt(abs(getsol(generation(b,t))),6,0))
writeln(";")
end-do
```

```
forall(tt in TimeInterval) do
forall(b in BidsDn) write(strfmt(-getsol(generation(b,nTime)),5,0))
forall(b in BidsUp) write(strfmt(abs(getsol(generation(b,nTime))),6,0))
writeln(";")
end-do
writeln("];")

writeln("TotalPowerActivatedUp = [")
write(sum(b in BidsUp, t in Time) getsol(generation(b,t))/12)
writeln("];")

writeln("TotalPowerActivatedDn = [")
write(sum(b in BidsDn, t in Time) getsol(generation(b,t))/12)
writeln("];")


write("AfrrActivation = [")
forall(t in Time, tt in TimeInterval | t < nTime) do
write(strfmt(getsol(afrr(t)),6,0))
writeln(";")
end-do
forall(tt in TimeInterval) do
write(strfmt(getsol(afrr(nTime)),6,0))
writeln(";")
end-do
writeln("];")


write("ImbalanceForecast = [")
forall(t in Time, tt in TimeInterval | t < nTime) do
write(strfmt(REALIMB(t),6,0))
writeln(";")
end-do
forall(tt in TimeInterval) do
write(strfmt(REALIMB(nTime),6,0))
writeln(";")
end-do
writeln("];")

write("Frequency = [")
forall(t in Time,tt in TimeInterval | t < nTime) do
write(strfmt(getsol(Frequency(t)),6,3))
writeln(";")
end-do
forall(tt in TimeInterval) do
write(strfmt(getsol(Frequency(nTime)),6,3))
writeln(";")
end-do
writeln("];")


writeln("\n%Obj. value: ", getobjval)
writeln("\n%Activation costs: ", getsol(ActivationCost))
writeln("%Penalty costs: ", getsol(FreqDevCost))
writeln
!  COST elements
forall(s in Stages | s >= Stage) do
StageActCost(s) := sum(b in BidsUp, t in StageTime(s)) getsol(generation(b,t))*BIDPRICE(b)*loTime/60 +
sum(b in BidsDn, t in StageTime(s)) getsol(generation(b,t))*(PRICE-BIDPRICE(b))*loTime/60
StageFDCost(s) := sum(t in StageTime(s)) (PenaltyPart2*(getsol(FrequencyOver2(t)) + getsol(FrequencyUnder2(t)))) +
sum(t in StageTime(s))(PenaltyPart1*(getsol(FrequencyOver1(t)) + getsol(FrequencyUnder1(t))))
writeln("%Stage ", s, ": ", strfmt(getsol(StageActCost(s)),10,1), strfmt(getsol(StageFDCost(s)),10,1))
end-do



fclose(F_OUTPUT)

fopen("BidPriceData.m",F_OUTPUT)
```

```
write("Price = [")
forall(b in Bids) write(strfmt(BIDPRICE(b),6))
writeln("];")
writeln

write("Volume = [")
forall(b in Bids) write(strfmt(BIDCAP(b),6,0))
writeln("];")
(!
write("Duration = [")
forall(b in Bids) write(strfmt((sum(t in Time) 5*getsol(activated(b,t))),4,0))
writeln("];")
writeln
!)
write("Names = [")
forall(b in Bids) write("'",b,"'")
writeln("];")
writeln

write("BidPType = [")
forall(b in Bids) write("'",BIDPTYPE(b),"'")
writeln("];")
writeln

fclose(F_OUTPUT)

end-procedure

! Generate initialization for next stage
procedure stageshiftoutput
FileName := Prefix + "Stage" + string(Stage)+".dat"
writeln("Writing data to ", FileName)
fopen(FileName,F_OUTPUT)
writeln("BIDSTATUS: [")
forall(b in Bids) do
writeln(
"(", b, ")",strfmt("",18-getsize(b)) ,"[", getsol(activated(b,NextStage)),
strfmt(round(getsol(generation(b,NextStage))), 5),
strfmt(Uptime(b,NextStage), 5),
"]")
end-do
writeln("]")

fclose(F_OUTPUT)
end-procedure
end-model
```

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