

Master's Programme in Advanced Energy Solutions

The impact of the market time unit shift production ramping on the power system balance

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Abstract

Fast scheduled active power changes at the shift of the market time unit (MTU) cause hour shift imbalances and frequency deviation in the Nordic power system. Therefore, active power ramping restrictions are applied in the Nordic synchronous system to limit the hour shift ramping of the high-voltage direct current (HVDC) transmission and the active power production.

Rapid increase in the variable renewable energy generation capacity poses challenges to the power system balancing. To ensure a better planned power balance and to improve the integration with the common European electricity market platforms, 15-minute imbalance settlement period (ISP) will be introduced in the Nordic power system in 2023. The introduction of the 15-minute ISP and later the launch of the quarter-hourly day-ahead, intraday, and balancing energy markets will affect the MTU shift production changes. Consequently, the current ramping restrictions designed for the hourly production changes need to be reassessed.

This thesis evaluates the need for developing new production ramping restrictions after the introduction of the 15-minute ISP and the quarter-hourly electricity markets. The hour shift changes in the active power production are analyzed and the impact of the 15-minute ISP on the MTU shift production changes is assessed. The effect of linear production ramping on the power system frequency is simulated to gain a better understanding on how the power system reacts to the MTU shift production changes.

Based on the conducted analyses and the previous research, the thesis concludes that restricting the production ramping might be necessary even after the introduction of the 15-minute ISP and the quarterly electricity markets. Quarterly balancing will reduce the hour shift imbalances, but the volume of the imbalances depends on how willing the market participants are to address their quarterly imbalances in the 15-minute day-ahead and intraday markets. Ultimately, the changes in the demand affect the volume of the production ramping at the MTU shifts. Moreover, wind power ramping caused by negative day-ahead prices may pose a risk for substantial MTU shift production changes in the future power system.

Keywords Power system balancing, production ramping, active power ramping restrictions, 15-minute ISP, hydropower ramping, wind power ramping

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Tiivistelmä

Kaupankäyntijakson vaihteen nopeat suunnitellut pätötehomuutokset aiheuttavat tunninvaihteen tase- ja taajuuspoikkeamia pohjoismaisessa sähköjärjestelmässä. Tasepoikkeamien vähentämiseksi pohjoismaisella synkronialueella sovelletaan pätötehon muutosrajoituksia erikseen suurjännitetasavirtalinkkien siirroille ja sähkötuotannon muutoksille.

Vaihtelevan uusiutuvan energiatuotantokapasiteetin kasvu vaikeuttaa sähköjärjestelmän tasapainottamista. Järjestelmän tasapainon takaamiseksi ja yhteisille eurooppalaisille sähkömarkkina-alustoille liittymiseksi 15 minuutin taseselvitysjakso otetaan käyttöön pohjoismaisessa sähköjärjestelmässä vuonna 2023. Varttitaseen ja myöhemmin 15 minuutin day-ahead-, intraday- ja säätösähkömarkkinoiden käyttöönotto vaikuttaa kaupankäyntijakson vaihteen tuotantomuutoksiin, minkä seurauksena nykyisiä tunninvaihteen tehomuutosrajoituksia on tarve uudelleenarvioida.

Tämä diplomityö arvioi kaupankäyntijakson vaihteen tuotantorajoitusten tarvetta varttitaseen ja 15 minuutin markkinoiden käyttöönoton jälkeen. Työ tutkii nykyisiä tunninvaihteen tuotantomuutoksia ja 15 minuutin taseselvitysjakson vaikutusta tuotantomuutosten suuruuteen. Lisäksi työssä simuloidaan lineaaristen tuotantoramppien vaikutusta pohjoismaisen sähköjärjestelmän tasapainoon.

Analyysien ja aiemman tutkimuksen pohjalta työ päättelee, että tuotantomuutosten rajoittamiselle voi olla tarvetta vielä varttitaseen ja 15 minuutin sähkömarkkinoiden käyttöönoton jälkeen. 15 minuutin taseselvitys pienentää tunninvaihteen tasepoikkeamia, mutta tasepoikkeamien suuruus riippuu markkinatoimijoiden halusta tasapainottaa poikkeamansa 15 minuutin day-ahead- ja intraday-markkinoilla. Myös muutokset kulutuksessa vaikuttavat kaupankäyntijakson vaihteiden tuotantoramppien suuruuteen. Lisäksi negatiivisten day-ahead-hintojen aikaansaamat muutokset tuulivoimatuotannossa voivat lisätä kaupankäyntijakson vaihteen merkittävien tuotantomuutosten riskiä tulevaisuuden sähköjärjestelmässä.

Avainsanat Sähköjärjestelmän tasapainottaminen, tuotantomuutokset, pätötehon muutosrajoitukset, varttitase, vesivoiman tehomuutokset, tuulivoiman tehomuutokset

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Preface

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Helsinki, 30 May 2022
Väinö Valli

Symbols and abbreviations

Symbols

ω	Angular velocity
P_{hydro}	Hydropower production
W_k	Kinetic energy
J	Moment of inertia
K_V	Self-regulation of load
f	System frequency
P_L	System load
P_{total}	Total production

Abbreviations

ACE	Area Control Error
aFRR	Automatic Frequency Restoration Reserve
AOF	Activation Optimization Function
BRP	Balance Responsible Party
BSP	Balance Service Provider
CET	Central European Time
EPC	Emergency Power Control
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
FFR	Fast Frequency Reserve
FRCE	Frequency Restoration Control Error
HVDC	High-Voltage Direct Current
ISP	Imbalance Settlement Period
LFC	Load Frequency Control
mFRR	Manual Frequency Restoration Reserve
MTU	Market Time Unit
PMU	Phasor Measurement Unit
SOA	Nordic System Operation Agreement
SOGL	Guideline on electricity transmission system operation
TSO	Transmission System Operator
UFLS	Under Frequency Load Shedding

1 Introduction

Active power ramping restrictions are used in the Nordic synchronous system to regulate active power changes at the shift of the hourly market time unit (MTU). Different ramping restrictions are applied for the high-voltage direct current (HVDC) interconnectors and for the active power production. The need for restricting the production ramping arises from the differences in the ramping speed of the production, the HVDC transmission and the consumption. Some generation units can change their production very rapidly at the shift of the MTU whereas the consumption and the restricted HVDC transmission ramp more gradually. The difference in the ramping behaviour causes momentary imbalances at the MTU shift [1].

The share of variable renewable energy sources in the Nordic power system is increasing rapidly. As a result, maintaining the power system balance becomes more challenging. To efficiently balance the production and the consumption in the future, several changes in the electricity market model are carried out in the coming years. In 2023, 15-minute imbalance settlement period (ISP) will be introduced in the Nordic power system. After that, the MTU resolution of the intraday and balancing energy market will change to 15 minutes from the current 60-minute unit [2]. Later, also the day-ahead market will move to 15-minute MTU [3]. The higher MTU resolution helps the balance responsible parties (BRPs) to ensure a better planned power balance inside the hour [4].

After the introduction of the 15-minute ISP and the quarterly intraday and day-ahead markets, the old ramping restrictions designed for the hourly production schedules will become outdated. As the production plans change every 15 minutes, the volume of the production change between the consecutive 15-minute MTUs will be different from the production change between the hourly MTUs. On one hand, the need for restricting the production ramping and designing new ramping restrictions depends on the volume of the production change at the MTU shift. On the other hand, also the speed of the production change at the shift of the MTU affects the need for restricting the production ramping.

Different production technologies have different ramping characteristics. Particularly the hour shift ramping of the hydropower production can be substantial and as a result the current ramping restrictions mainly affect the hydropower ramping [5]. However, the rapid increase of the wind power production capacity in the Nordic synchronous system has raised concerns about the MTU shift ramping of wind power. Wind power ramping is typically not scheduled since the production varies according to the wind conditions. However, occasionally the negative day-ahead electricity prices can cause some of the wind power producers to curtail their production at the MTU shift, which can result in substantial scheduled changes in the wind power production [6].

The aim of this thesis is to evaluate the need for restricting the production ramping in the future Nordic synchronous system. Chapter 2 presents the theoretical background of the study. Chapter 3 analyses the production ramping in the Nordic synchronous system and particularly evaluates the effects of the hydropower and wind power ramping on the power system balance. The impact of the 15-minute MTU on the production changes is also assessed in Chapter 3. Chapter 4 simulates the effects of linear production ramping on the power system frequency using a MATLAB Simulink model of the Nordic synchronous system. Chapter 5 concludes the study and discusses the future of the production ramping restrictions.

2 Background

2.1 Power system balance and frequency stability

The Nordic synchronous system comprises of the subsystems of Finland, Sweden, Norway, and eastern Denmark [7]. The subsystems are synchronized to operate at the same nominal frequency of 50 Hz. The basic principle for maintaining the power system balance is that the electricity consumption and production must be equal. If more active power is produced than consumed, the system frequency will rise. Vice versa, if the consumption of active power exceeds the generation, the system frequency will decrease [8].

Imbalance between the production and the consumption cannot be completely avoided. Planning the production is based on forecasting how the demand for electricity will change. There can be errors in the forecasts that cause imbalance between the production and the consumption. Moreover, the controllability of the power plants and the consumption sources has physical limits, and failures can occur in the power system components [8].

Large deviations in the active power balance can compromise the system stability. If the frequency deviates too much from the nominal value, automatic protection mechanisms start disconnecting the power system generators [9]. This can eventually lead to blackouts in parts of the power system [8]. In the Nordic synchronous system, the transmission system operators (TSOs) are responsible of maintaining the power system balance and operational security [8].

2.1.1 Kinetic energy and system balance

The frequency of the power system results from the rotational speed of the synchronous generators connected to the grid [10]. The rotating masses of the generators and the turbines store kinetic energy that is crucial for the system balance. If the active power consumption is higher than the production, the consumption sources start to consume the kinetic energy stored in the rotating masses of the synchronous generators connected to the grid. This slows down the generators and decreases the system frequency. Vice versa, if the production is higher than the consumption, the kinetic energy of the synchronous generators will increase, which causes the generators to spin faster, and the system frequency will rise [11].

The kinetic energy of a rotating mass is

$$W_k = \frac{\omega^2 J}{2} \quad (1)$$

where J is the moment of inertia of the rotating mass and ω is the angular velocity of the mass. The amount of kinetic energy in the power system determines how fast the frequency will deviate after an occurrence of an imbalance between production and consumption [11]. The more the power system has kinetic energy, the better it can resist the frequency deviations caused by the imbalances [10].

The Nordic power system is synchronized to the nominal frequency of 50 Hz. In the normal operation the changes in the system load are small compared to the kinetic energy of the whole power system and the frequency deviations are small. However, larger deviations in the power balance can cause the frequency to deviate outside the standard frequency range of 49.9-50.1 Hz [11].

Power deviation ΔP_L can be expressed as a derivative of the kinetic energy W_k .

$$\Delta P_L = \frac{dW_k}{dt} = \omega J \frac{d\omega}{dt} \quad (2)$$

The relation between a change in the frequency and the kinetic energy can be derived based on Equations 1 and 2.

$$\frac{d\omega}{dt} = \frac{\Delta P_L}{\omega J} = \frac{2\omega \Delta P_L}{2\omega^2 J} \quad \omega^2 J = 2W_k \quad (3)$$

$$\frac{d\omega}{dt} = \omega \frac{\Delta P_L}{2W_k} \leftrightarrow \frac{df}{dt} = f \frac{\Delta P_L}{2W_k} \quad (4)$$

When the kinetic energy of the system is known, the speed of the frequency deviation immediately after the imbalance can be calculated using Equation 4. Similarly, the amount of kinetic energy in the system can be calculated based on the magnitude of the power deviation and the speed of frequency deviation [11].

The role of kinetic energy is becoming increasingly important in the future power system as the share of renewable generation is increasing. Renewable energy generation is often electrically decoupled from the grid with a power converter and thus unable to provide kinetic energy to the grid. As a result, the power system becomes more vulnerable to changes in the load. However, new converter control strategies have been developed to provide the power system with virtual or synthetic inertia. These converters usually mimic the inertial response of the synchronous generators by delivering active power proportional to the speed of frequency change [12].

2.1.2 Self-regulation of load

Part of the power system load is frequency dependent meaning that when the frequency decreases the load decreases and vice versa. This power system property is called self-regulation of load. Self-regulation of load stops the frequency from deviating past a certain level even if there are no other means of frequency control in the power system. If the power system load at the nominal frequency is P_{L0} the power system load at other frequencies $P_L(t)$ can be expressed as

$$P_L(t) = P_{L0} + K_v \Delta f(t) \quad (5)$$

where K_v is the self-regulation of load. The unit for K_v can be expressed as %/Hz or MW/Hz [11]. According to [11] the amount of load self-regulation in the Nordic synchronous system is 1000 MW/Hz. According to [13] the amount is 1%/Hz.

2.1.3 Frequency stability

Frequency stability means the power system's ability to maintain stable frequency after a major imbalance between the production and the consumption. Frequency stability is dependent on the amount of kinetic energy and spinning reserve in the power system. Spinning reserve or frequency controlled instantaneous reserve is the capacity left in the power system generators that can be used for controlling the frequency [11].

Maintaining the frequency stability is usually less problematic in over frequency situations than in under frequency situations. If the frequency rises too high, generation can be reduced, or generators can be disconnected from the grid. Under frequencies can be more severe if there is no possibility to increase the generation or rapidly disconnect some of the load. In underfrequency situations, enough spinning reserve and kinetic energy is needed to stop the frequency from decreasing [11].

Since the generators are technically limited to operate in a particular frequency range around the nominal 50 Hz frequency, large deviations in the frequency can trigger automatic protection mechanisms that disconnect the generators from the grid [9]. If the frequency decreases too much the turbo-generator vanes can damage. Naturally, disconnecting generators in under frequency situation further increases the imbalance between the production and the consumption which can eventually cause a blackout in the system [11].

The main objective of maintaining frequency quality is to ensure that the supply of power is not interrupted by large frequency deviations. The power system should be able to withstand so called reference incident or dimensioning fault without interruptions in the supply or applying any emergency

measures [9]. Reference incident is the single largest power deviation that can occur in the synchronous system, and it is considered in the dimensioning of various reserves [10].

If the dimensioning of the reserves is not enough to ensure the frequency stability, different remedial actions are used in the Nordic system to prevent the frequency from collapsing. Emergency power control (EPC) is a protection mechanism that is implemented in several of the HVDC links that connect the Nordic synchronous system to the synchronous systems in the neighboring countries. If the frequency deviates too much from the nominal 50 Hz value, EPC starts feeding power to the system to prevent the disconnection of generators or load. The activation ranges for EPC are 49.5-49.0 Hz in under frequency situations and 50.5-50.1 during over frequencies [10].

Underfrequency load shedding (UFLS) is an automatic emergency measure that is applied as the last means to prevent the frequency from decreasing to a level where the automatic protection mechanism starts disconnecting the generators connected to the grid. UFLS starts disconnecting the power system load in stages at certain frequency levels until the frequency has stopped decreasing. The first stage of UFLS is activated if the frequency drops under 48.8 Hz [9].

2.1.4 Reserves

The TSOs maintain the power system balance and frequency quality using reserves. Reserves are power plants or consumption sources that can adjust their generation or consumption to balance the power system. Balancing service providers (BSP) can offer different types of reserve products in the balancing markets administrated by the TSOs. The TSOs will procure the needed reserves from the markets according to the power system needs [14].

Frequency control reserves used in the Nordic power system can be divided into three categories based on their use. Frequency containment reserves (FCR) are the first reserves to react to the imbalances in the power system and they aim at stabilizing the frequency and maintaining the frequency quality. FCRs are activated based on the measured frequency deviation. Frequency restoration reserves (FRR) are used for bringing the frequency back to the nominal 50 Hz after the frequency has deviated and for recovering the activated FCR capacity back into use. Fast frequency reserve (FFR) is used when the kinetic energy in the power system is low and there is a risk for a major imbalance [10].

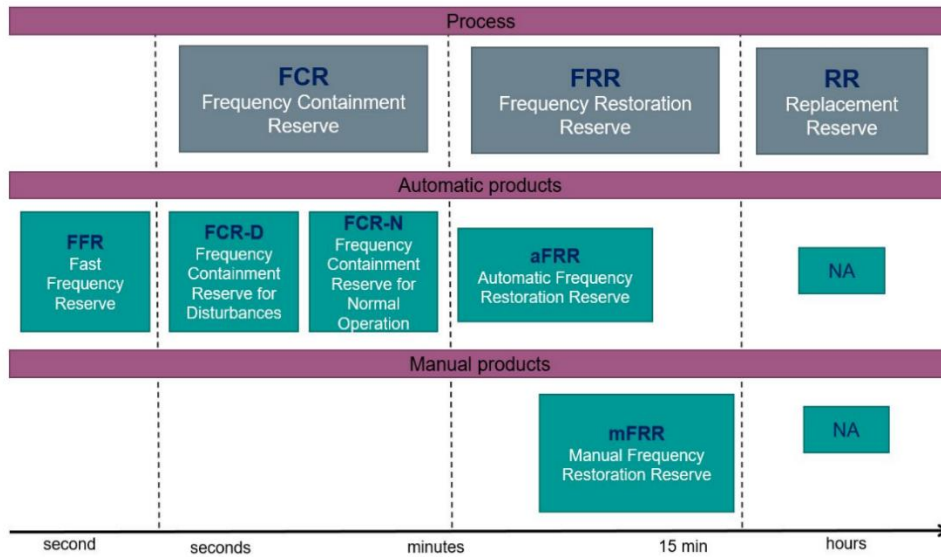


Figure 1: Reserve products in the Nordic power system [14].

Frequency containment reserve for normal operation (FCR-N) is used for constantly controlling the frequency inside the standard frequency range. FCR-N must fully activate in 3 minutes and adjust symmetrically to both directions. The minimum required amount of FRC-N in the Nordic synchronous system is 600 MW. Currently there are only national markets for the procurement of FCR-N, but the TSOs can procure FCR-N from the national market and sell it to the other TSOs [10].

Frequency containment reserve for disturbances (FCR-D) is used for stopping the frequency deviation during disturbances. The purpose of FCR-D is to ensure that the frequency deviation does not exceed the maximum instantaneous frequency deviation (see Chapter 2.1.5) and to guarantee frequency stability outside the standard frequency range [8]. There needs to be enough FCR-D capacity to cover the reference incident in both upwards and downwards directions [10].

There are two separate products for upwards and downwards regulation of FCR-D. FRC-D activates when the frequency deviates outside the standard frequency range and must be fully activated when the frequency has deviated 0.5 Hz from the 50 Hz value. Full activation takes 30 seconds. As with FCR-N, currently there are only national markets for FCR-D, but the capacity can be exchanged between the TSOs [10].

Fast frequency reserve (FFR) is used to complement FCR-D in situations where the kinetic energy of the power system is low, and FCR-D is not fast enough to stabilize the frequency during a large imbalance. FFR activates fully in 0.7-1.3 seconds depending on the frequency level at the time of the activation. Dimensioning of FFR is based on estimates of the kinetic energy in the system and the simulations of the valid reference incident at the target day [10].

Automatic frequency restoration reserve (aFRR) is used for restoring the frequency back to 50 Hz and for releasing the activated FCR back into use. aFRR is activated with a separate activation signal from the connecting TSO. The reserve capacity must be fully activated in 2-5 minutes from sending the signal. aFRR is obtained when maintaining good frequency quality is difficult, such as morning and evening hours when the changes in production and consumption are large [10]. Currently the acquired aFRR capacity is 300 or 400 MW. aFRR is acquired for every hour except hours 2-5, hour 1 being the first operational hour of the day [15].

At the present, there are only national aFRR capacity markets and the total volume of obtained aFRR is distributed between the Nordic countries. [10]. However, common Nordic aFRR capacity market will be introduced in future as part of the Nordic balancing model cooperation. Moreover, the Nordic TSOs will later connect to the common European aFRR energy activation platform (PICASSO) [16].

Manual frequency restoration reserve (mFRR) is a manually activated reserve product used for restoring the frequency back to its nominal value and for releasing the activated FCR back into use. The TSOs procure mFRR from the Nordic balancing energy market. There are also national mFRR capacity markets and other solutions to ensure enough capacity to cover the national reference incident of each country. In the balancing energy market, BSPs can leave bids for upwards and downwards regulation of mFRR. The TSOs then activate the bids needed to balance the power system. Full activation of mFRR takes 15 minutes [10].

Nordic mFRR energy activation market (EAM) will be launched in the end of 2023. After the go-live, the BSPs can make bids in 15-minute resolution. However, the marginal pricing for the quarterly bids will be implemented later. The latest time for the implementation of the quarterly pricing is when connecting to the common European mFRR EAM platform (MARI) [17]. Common Nordic mFRR capacity market will be also introduced in the end of 2023 [16].

2.1.5 Target parameters for frequency quality

Monitoring and maintaining frequency quality is important for ensuring the security of supply in the synchronous area [8]. The framework for defining the frequency quality in the Nordic synchronous system is presented in the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter SOGL). In accordance with SOGL the Nordic TSOs have proposed common frequency quality defining parameters as well as the frequency quality target parameter for monitoring the frequency quality [18, 19].

The frequency quality defining parameters are used for designing the power system control processes and reserve dimensioning. The parameters

include ranges and restoration times for the frequency [18]. Table 1 presents the frequency quality defining parameters and Figure 2 illustrates how the parameters are defined. The frequency quality defining parameters and the frequency quality target parameter are described in more detail below according to [9].

Frequency quality defining parameters	
nominal frequency	50 Hz
standard frequency range	± 100 mHz
maximum instantaneous frequency deviation	1000 mHz
maximum steady-state frequency deviation	500 mHz
time to restore frequency	15 minutes
frequency restoration range	± 100 mHz
alert state trigger time	5 minutes

Table 1: Frequency quality defining parameters in the Nordic synchronous system [9].

Standard frequency range and nominal frequency are crucial frequency quality defining parameters. The standard frequency range is defined as a symmetrical ± 100 mHz range around the nominal 50 Hz frequency and it is the normal operation range for the frequency in the Nordic synchronous area. Other frequency defining parameters specify the ranges and restoration times for frequency after the largest possible imbalance i.e., the reference incident has occurred.

Maximum instantaneous frequency deviation is 1000 mHz allowing instantaneous frequency deviation down to 49.0 Hz or up to 51.0 Hz from the nominal 50 Hz value. UFLS will activate at 48.8 Hz, meaning that there is a 200 mHz buffer between the maximum instantaneous frequency deviation and the triggering of the UFLS. This has been considered reasonable since the frequency values can vary geographically and there can also be errors in the model and the measurements.

Maximum steady-state frequency deviation sets the limit on how far from 50 Hz the system frequency is allowed stabilize after an imbalance has occurred. Steady state is defined as the state where the frequency containment process has been completed and the frequency restoration process must begin.

After the occurrence of the reference incident the frequency must restore inside the ‘frequency restoration range’ in ‘time to restore frequency’. The frequency restoration range is defined the same as the standard frequency range. The time to restore frequency is defined to be 15 minutes since there needs to be enough time to for the mFRR to activate.

Alert state trigger time is related to the power system operational states defined in the SOGL Article 18. Alert state trigger time means the time before the alert state becomes active. The Nordic TSOs define the alert state trigger time as the time after the disturbance during which the 60 s rolling average of the frequency has exceeded 50 % of the maximum steady state frequency deviation (250 mHz) for 5 minutes.

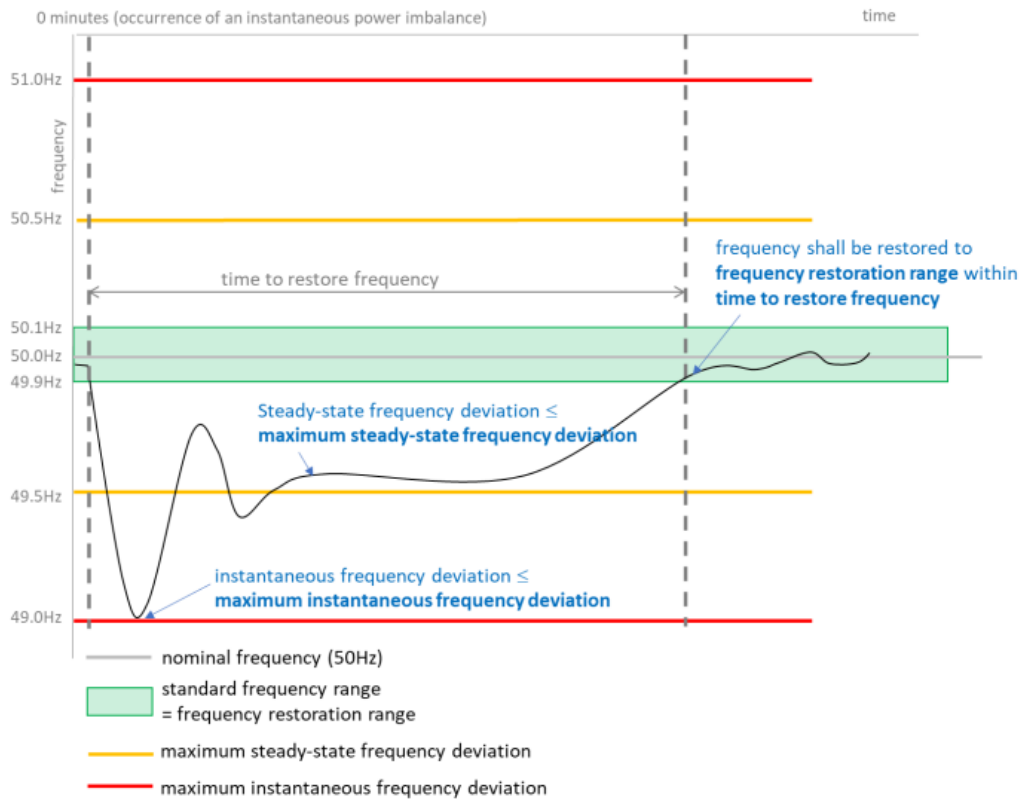


Figure 2: Frequency quality defining parameters illustrated [9].

The frequency quality target parameter is specified as the maximum number of minutes outside the standard frequency range. In the Nordic synchronous area, the time outside the standard frequency range should not exceed 15 000 minutes per year. Moreover, the Nordic TSOs have agreed to aim at less than 10 000 minutes outside the standard frequency range per year, but this aim should not be considered as the absolute maximum limit.

2.2 Nordic electricity market

The Nordic electricity market consists of multiple different markets that are used to efficiently balance the supply and demand of electric power. The TSOs role in the electricity markets is to transfer electricity to the distribution system operators or directly to large consumers [20]. The TSOs are also responsible of maintaining the power system balance by procuring balancing services from BSPs that operate in the balancing markets [21].

The wholesale markets for physical power are day-ahead market, intraday market, and balancing markets. There are also financial electricity markets, where electricity derivatives such as futures and options are traded. Financial markets do not have physical trade of electricity in the Nordic power system [20].

The electricity markets are operated in different timeframes. Day-ahead market is used as a baseline for planning the production and the consumption for the 24-hour period of the upcoming day [22]. Intraday market is used to better balance the supply and demand of electricity closer to the actual hour of delivery [23]. The final balancing during the operational hour is carried out in the balancing markets controlled by the Nordic TSOs [24].

2.2.1 Day-ahead and intraday markets

In the day-ahead market, the market operators can leave bids for selling or buying electricity for each hour of the upcoming day in a closed auction. The bids must be submitted at 12:00 central European time (CET) for the electricity delivery on the next day [22]. The offers to sell or buy electricity are combined to form supply and the demand curves for each hour and each bidding area [25].

The day-ahead price is affected by the available transmission capacities between different geographical areas that correspond to the bidding areas. If there are transmission capacity bottlenecks between the bidding areas, the day-ahead market prices can vary depending on the area. The electricity will flow from the low-price area to the high-price area where the demand is high, or the production is low [26].

The area prices are calculated for every bidding area. In deficit area, the area price is higher compared to the area price in the surplus area [26]. Figure 3 illustrates, how the area prices are formed in surplus and deficit areas and how the available transmission capacity is considered in the area price calculation.

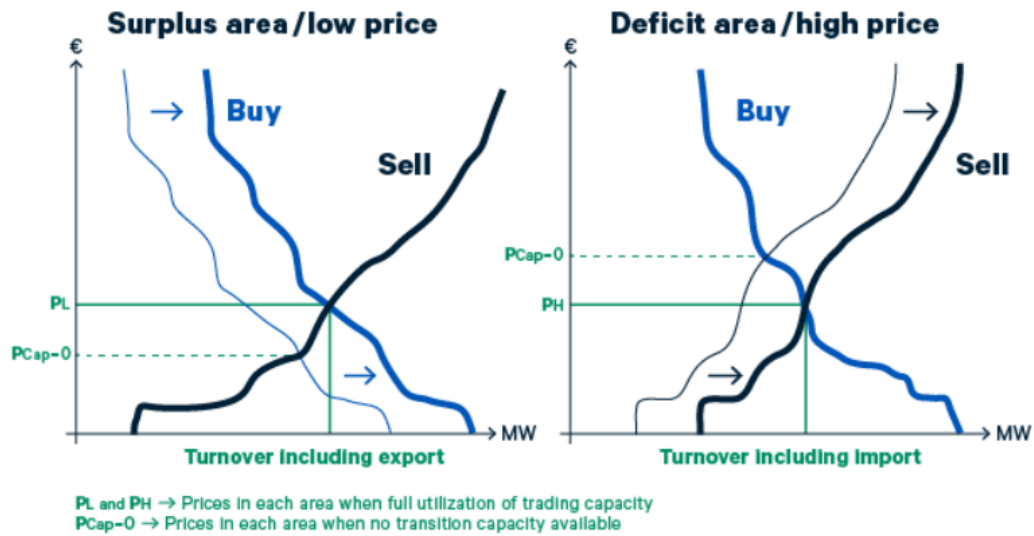


Figure 3: The formation of area price [26]. In surplus area the buy-curve is shifted to the right according to the available transmission capacity for the export which raises the area price. In deficit area the sell-curve is moved to the right according to the available transmission capacity for the import which lowers the area price [26, 25].

Intraday market is an aftermarket for the day-ahead market that is used for adjusting the trades closer to the electricity delivery and for balancing the supply and the demand on the operational hour in case there have been errors in the forecasts made earlier [24, 25]. Intraday is a continuous market and it is open until one hour before the electricity delivery. In some cases, the intraday market is continued until the delivery. Intraday trades are based on first-come, first-served principle. The highest-price offers for buying electricity and the lowest-price offers for selling electricity come first [23].

Currently the day-ahead and intraday markets operate on hourly resolution. However, sometime after the introduction of the 15-minute ISP, the intraday market will move to 15-minute resolution [27]. Later also the 15-minute day-ahead market will be introduced in the Nordic power system [3]. The schedule for the changes in the market resolution is currently under assessment [16].

2.2.2 Balancing responsibility

The electricity market law states that the electricity market participants are responsible of consuming and generating electricity according to their production and procurement contracts during each hour. However, there are always uncertainties in the consumption forecasts that are used as the basis for the production [25]. Furthermore, there can be failures in the production, the

consumption, or the grid [28]. Consequently, the market parties cannot perfectly balance their production and consumption themselves.

To maintain the continuous power balance, every electricity market party must have an open supplier that is responsible for ensuring that the party's forecasted and actualized production or consumption are in balance. The open supplier is obliged to deliver power to the market party according to the real consumption of the party. The TSOs are the highest-level open suppliers. The market parties whose open supplier is the system operator are called balance responsible parties (BRP) [25]. The BRPs need to balance their portfolio before the operational hour by trading in day-ahead and intraday markets and making bilateral trades with other BRPs in the bidding area [29].

Since the TSOs are responsible of the system balancing during the operational hour, the BRPs need to provide the TSOs with production plans. The hourly production plans for the next day are provided after the day-ahead trade. The gate closure time for the final adjustments in the production plans is 45 minutes before the operational hour in other Nordic countries except Finland. In Finland, the production plans can be updated until 25 minutes before the operational hour. The TSOs use the production plans for planning the balancing during the operational hour [29]. The TSOs balance the power system by procuring different reserves from the BRPs operating in the balancing markets as explained in Chapter 2.1.3.

After the electricity delivery, the actualized volumes of the provided and procured electricity are settled in imbalance settlement. The highest link in the Nordic imbalance settlement hierarchy is eSett Oy. eSett is responsible of the imbalance settlement of the individual BRPs [28]. Single balance model for imbalance settlement was introduced in the Nordic system in November 2021. In the previous imbalance settlement model, the imbalances were calculated separately for the production and the consumption of the BRP. However, in the single balance model the imbalance volume of the BRP is calculated and settled in a single imbalance [30].

The imbalance is calculated based on the electricity trades of the BRP, the measured production and consumption of the BRP, the imbalance in the metering grid area and the made imbalance adjustments. If the sum of the beforementioned components is not zero, the BRP needs to either buy imbalance energy from eSett or sell imbalance energy to eSett. For example, if the BRP has consumed and sold more electricity than it has produced or purchased, the BRP needs to buy imbalance energy from eSett to cover the deficit [28].

2.2.3 Nordic balancing model and introduction of 15-minute ISP

Maintaining the power system balance becomes increasingly challenging in the coming years. The rapid increase of renewable energy generation and the changing consumption patterns make it harder to predict the production and consumption [31]. At the same time the Nordic balancing markets need to become more and more integrated with the European balancing markets. The Nordic TSOs have established a joined effort called Nordic Balancing Model (NBM) for creating a new model for balancing the Nordic power system in the future [16].

The NBM roadmap includes several big changes to the Nordic electricity markets and the power system balancing. Common Nordic markets for aFRR and mFRR capacity will be introduced as well as the automated Nordic EAM for mFRR. Later, the Nordic TSOs will also connect to the common European energy activation market platforms for aFRR and mFRR [16].

The next step in the NBM project comes when the 15-minute ISP is introduced in 2023. After the go-live date, the imbalance settlement will be done in 15-minute periods instead of the current 60-minute periods. However, the pricing of the imbalances will still be hourly. The 15-minute imbalance pricing will be taken into use later, after the quarterly balancing energy market and the 15-minute cross-border intraday trade is introduced [2].

The 15-minute intraday market allows BRPs to make quarterly adjustments in their portfolio after the hourly day-ahead market has closed. Similarly, the 15-minute balancing energy market allows the TSOs to balance quarter-hourly imbalances after the day-ahead and intraday trade [27]. A major driver for making the quarterly adjustments in the intraday market is that the BRPs must go through the imbalance settlement and the possible cost of not being balanced every 15-minutes. The BRPs need to decide whether is it more beneficial to balance their imbalances by trading in the intraday market or go through the imbalance settlement and let the TSOs do the balancing in the balancing energy markets [32].

In terms of power system stability, the most important aspect of the 15-minute ISP and the quarterly markets is that the BRPs can more efficiently address their sub-hour imbalances and reduce so called structural power system imbalances. The structural imbalances are caused by the market design and are usually predictable. The quarterly balancing in the intraday and balancing energy markets will help to reduce the structural imbalances caused by the mismatch between the production and the consumption on a sub-hour timeframe. Consequently, the frequency quality will improve and the need for frequency and balancing reserves will be reduced [4].

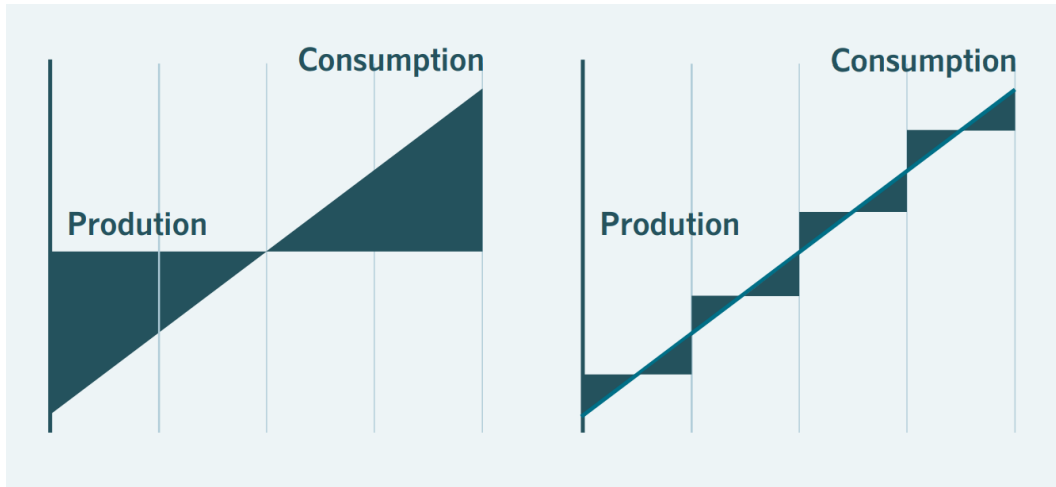


Figure 4: An illustration of the effect of the quarter-hourly markets on the structural imbalances [4]. On the left, the hourly market is illustrated. The production remains constant throughout the hour but in this case the consumption increases with a linear ramp. This results in large imbalances (the blue area). On the right, the quarterly market is illustrated. The production changes four times during the operational hour, which significantly reduces the imbalances.

As the 15-minute ISP and the quarterly intraday and balancing energy markets are introduced, the balancing model of the Nordic synchronous area will change to consider balances of individual bidding areas instead of the frequency of the whole synchronous system. The new balancing model is called area control error (ACE) model. The concept of the ACE model is that the TSOs responsible of the bidding areas will forecast the quarter-hourly balancing need for the bidding areas. The balancing requests are sent to activation optimization function (AOF) that will select the best bids for balancing each bidding zone while taking the cross-zonal capacities consideration [10]. When every bidding area is in balance, ultimately the whole Nordic synchronous system will be in balance. The Nordic AOF will be used to clear the mFRR EAM before the Nordic market is integrated into European mFRR energy activation market platform (MARI) [33].

2.3 Active power ramping restrictions

Momentary imbalances of the power system are caused by the momentary differences between the production or the electricity import and the consumption or the electricity export. Although the generation units aim to keep their production stable over the ISP, imbalances can still occur especially during the ramping period between consecutive ISPs. The fundamental reason for the imbalances is that the generation units tend to ramp up quickly to the new production setpoint whereas the demand increases in a linear manner. The same principle applies to the imbalances caused by the difference in the ramping speed of the rapidly ramping generators and gradually ramping HVDC interconnectors [1].

To limit the momentary imbalances caused by the active power ramping, the Nordic TSOs apply measures that aim to alleviate the effects of the momentary imbalances. For example, frequency deviations can be mitigated by procuring reserves. Other measures aim to reduce the imbalances themselves. Since the trading plans of the HVDC interconnectors and the production plans of the BRPs can change substantially at the hour shift, active power ramping restrictions are applied to limit the minute-by-minute imbalances caused by the changes in the production and the HVDC flows [1].

General guidelines for the ramping restrictions for the active power output are given in the SOGL Article 137(3) and (4). Article 137(3) provides guidelines for the HVDC interconnector power output ramping restrictions. Guidelines for the production ramping restrictions are given in Article 137(4) [19]. The Nordic TSOs have agreed on the detailed ramping restrictions for active power output in methodology “Amended Nordic synchronous area methodology for ramping restrictions for active power output in accordance with Article 137(3) and (4) of the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation” [34].

The restrictions for the HVDC interconnectors limit the change in the commercial flow of the HVDC interconnectors between a bidding zone in the Nordic synchronous system and a bidding zone in another synchronous system. The commercial flow of an interconnector is allowed to change 600 MW from one hour to the next and the ramping speed is limited to 30 MW/minute. There are more specific rules for combinations of certain interconnectors and also exceptions or additions to the above-mentioned rules [34].

Whilst the subject matter of this thesis does not cover the ramping restrictions for the HVDC interconnectors it should be noted that all the measures used to mitigate or limit the momentary imbalances, including e.g., HVDC ramping restrictions, production ramping restrictions and the procurement of aFRR, affect each other and the frequency quality in the Nordic synchronous system. Identifying specific effects of all the measures is very difficult [1].

2.3.1 Restrictions for production ramping

The actions specified in the SOGL Article 137(4)(a) and (b) include obligations on ramping periods, maximum ramping rates and individual ramping starting times for power generating modules and/or demand units. Article 137(4)(c) allows coordinating the ramping between power generating modules, demand units and active power consumption in the LFC block [19]. Based on the Article 137(4), the Nordic TSOs have specified two rules for restricting the production ramping.

The first production ramping rule is implemented when the hourly production plan of a power generating module represented by the BRP changes more than 200 MW at the hour shift. The BRPs with over 200 MW change in the production plans must reschedule their production plans with 15-minute steps around the hour shift. The first step starts 15 minutes before the hour shift, the second step starts at the hour shift, and the third step starts 15 minutes after the hour shift [34]. The quarterly steps help the production to better follow the ramps of the demand and the HVDC exchange at the hour shift and thus reduce the minute-by-minute imbalances [5]. The quarterly steps are used in Sweden, Norway, and Finland but not in Eastern Denmark due to the production characteristics. Furthermore, in Norway the steps can be applied from 30 minutes before the hour shift to 30 minutes after the hour shift [34].

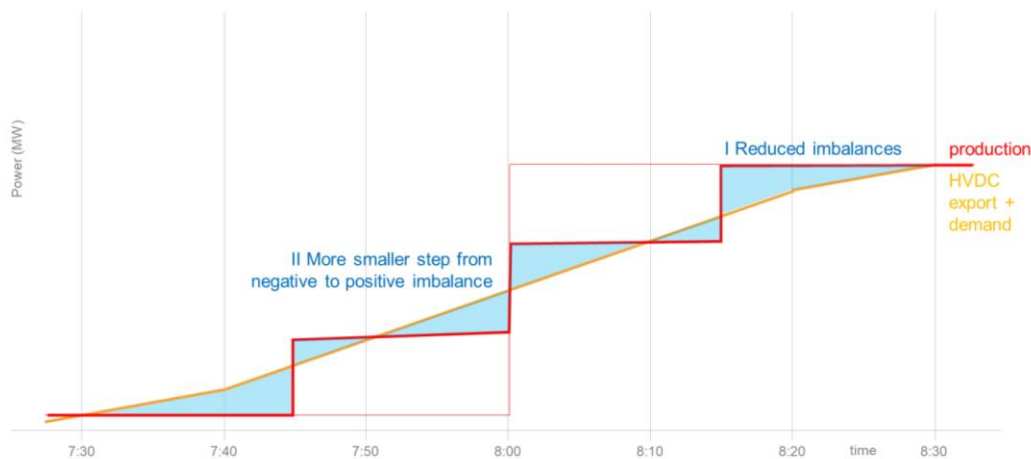


Figure 5: Illustration of the rescheduled production plans with quarter-hourly steps [5]. The quarterly steps help the production to better follow the demand and the HVDC export that ramp in a linear manner. This results in smaller imbalances.

The second rule allows the TSOs to coordinate the hour shift production ramping by asking the BRPs to either delay or advance parts of the planned production steps at the hour shift. The new power schedules can be applied

from 30 minutes before the hour shift till 30 minutes after the hour shift. The rescheduling is done in order to maintain the power system balance in situations where the changes in the planned production and HVDC exchange will affect the system frequency in a way that cannot be completely taken care of by the control centers [1].

The production ramping is assessed based on planning information and real-time data on a national level and on a synchronous area level. If the changes in the production plans seem to be high, a coordinated plan of flattening the changes is made by the TSOs and the rescheduling of the production is agreed with the BRPs. Coordinating the production is important during the morning and evening hours and around midnight [1].

2.3.2 Assessment of current production ramping restrictions

In 2020, an assessment of the efficiency of the current ramping restrictions was made by the Nordic TSOs. The assessment covers both operational and market issues of the ramping restrictions and evaluates the effectivity and cost-efficiency of the current ramping rules. According to the assessment the specifications for the current production ramping restrictions influence which BRPs are restricted by the rules and which countries must utilize ramping rules the most. Furthermore, the size of the BRP also affects whether the BRP is restricted by the ramping rules or not [5].

Although the current production ramping rules concern all BRPs, at the present mainly BRPs with hydropower units with storage are affected by the rules since they are capable of ramping very fast at the hour shift. According to the assessment, other types of production units are either not able to ramp fast enough to be restricted by the ramping rules or can hardly adjust at all. As Figure 6 illustrates, thermal units naturally ramp with a constant pace similar to the ramping of demand and are therefore indirectly following the ramping restrictions. On the other hand, aggregated intermittent generation ramps in a stochastic manner and would not even be capable of ramping according to a stepwise profile. Run-of-river units are mostly too slow to ramp to be restricted by the ramping rules.

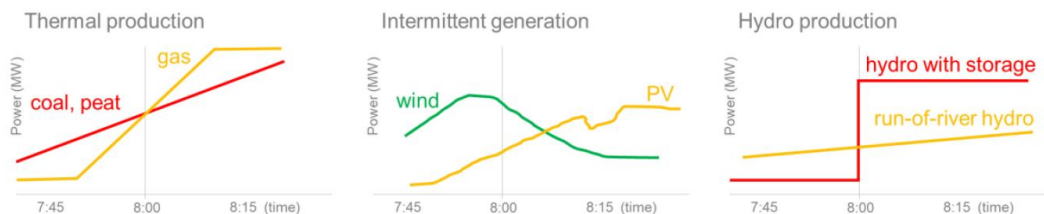


Figure 6: Illustration of the ramping behavior of different production units. [5]

Since mainly the hydro units with storage are affected by the ramping rules, most quarterly adjustments take place in Norway where there is a significant amount of hydropower production with storage. Unlike in Finland and Sweden, in Norway quarterly production steps can be applied 30 minutes before the hour shift until 30 minutes after the hour shift to better reduce the minute-by-minute imbalances. Norway also has an additional rule for over 400 MW production changes at the hour shift [5].

According to the assessment, mainly large BRPs with several hydro units with storage are likely to change their production more than 200 MW at the hour shift and are hence more likely to be affected by the ramping requirements than smaller BRPs. The ramping rules are therefore relevant for the 5-6 largest production companies in Norway, 3-4 in Sweden and 3-4 in Finland.

In principle, the limit for the change in production plans at the hour shift could be lower and consequently the ramping rules could also affect smaller BRPs with less hydro units with storage. However, the 200 MW limit for applying the ramping restrictions is considered fair since it is more efficient to apply the production steps with many available hydro units. With several hydro units, the steps can be scheduled in a way that allows the units to operate at their most optimal set-point. Smaller BRPs with less units would have to run their units outside the optimal set-point, which would result in energy and efficiency losses in the power system and would be harmful for the level playing field [5].

Since applying the quarterly production steps can be done efficiently without major energy losses, the BRPs receive no financial compensation for applying the steps. However, if a TSO utilizes the second ramping rule for advancing or delaying parts of the production steps at the hour shift, the affected BRPs receive financial compensation. In 2019, the total amount of shifted production was 403 GWh and the paid financial compensation was 2,8 million euros [5].

3 MTU shift production ramping

The current active power ramping restrictions are considered an efficient and cost-effective way of reducing the minute-by-minute imbalances around the hour shift [5]. However, the introduction of the 15-minute ISP and the quarter-hourly intraday and day-ahead markets will drastically affect the production ramping in the future power system. The rule for making quarterly steps in the production plans around the hour shift will become outdated when the BRPs start balancing quarterly imbalances in the 15-minute intraday and day-ahead markets. To estimate the need for restricting the production ramping in the future, this chapter analyzes the effects of fast MTU shift production changes in the current power system by carrying out different analyses for various sets of production and frequency data. The impact of the 15-minute markets on the volume of the production changes is also analyzed and reviewed.

3.1 Active power ramping

This chapter studies whether the frequency deviations at the hour shifts are dependent on the volumes of change in the total Nordic production and the volumes of change in the HVDC transmission. The hypothesis of the study is that large changes in the hourly active power production or HVDC transmission require faster ramping speed and are thus more likely to cause momentary imbalances at the hour shift.

Figure 7 represents the changes in the average frequency around the hour shift as a function of hourly changes in the total Nordic production in 2021. The change in the average frequency around the hour shift was calculated by subtracting the average frequency value 5 minutes before the hour shift from the average frequency value 5 minutes after the hour shift. Positive frequency change means that the average frequency value has increased after the hour shift. The resolution of the frequency data is 1 second. The production change was calculated by subtracting the total Nordic production value of the previous hour from the production value of the following hour. The original production data is expressed as energy in MWh. However, the hourly energy values in MWh also correspond to the hourly averages of power in MW and thus the changes in production are expressed in MW. Positive value means that the production has increased from the previous hour.

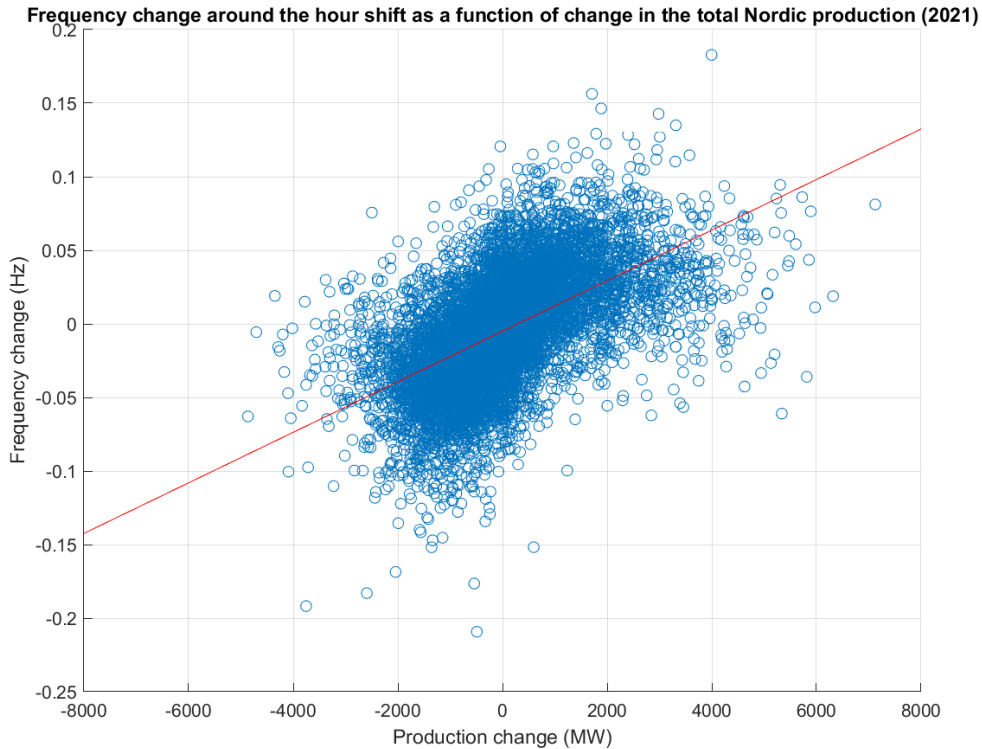


Figure 7: Scatterplot image of the average frequency changes around the hour shift as a function of the changes in the hourly total Nordic production in 2021. The least squares regression line gives a rough linear estimate of the dependency between the two variables. *Production data: Nord Pool [35]. Frequency data: Fingrid open data [36].*

As Figure 7 shows, there is a clear dependency between the average frequency changes around the hour shift and the changes in the hourly production values. Generally, more negative frequency changes occur when the production decreases from the previous hour and more positive frequency changes occur when the production increases from the previous hour. The correlation coefficient between the variables is 0.55. As can be seen from the figure, the frequency changes at the hour shift cannot be completely explained just by studying the volumes of the production changes. Whether the production change at the hour shift causes imbalance in the power system depends on the volume and the speed of change of the production in relation to the volume and the speed of change in the consumption and the HVDC import or export. There can be also other random causes of imbalances at the hour shift, such as grid faults, that cannot be predicted.

In Figure 8, the previous analysis is carried out for the average frequency changes around the hour shift and the hourly changes in the HVDC transmission between the Nordic synchronous system and other synchronous systems. Figure 8 shows no clear pattern indicating the dependency between the

changes in the hourly HVDC flows and the changes in the average frequency values around the hour shift. The calculated correlation coefficient between the variables was -0.01 . Possible explanation for the result is that the commercial ramping speed of the HVDC interconnectors is currently restricted to 30 MW/minute which effectively decreases the imbalances caused by the HVDC ramping alone.

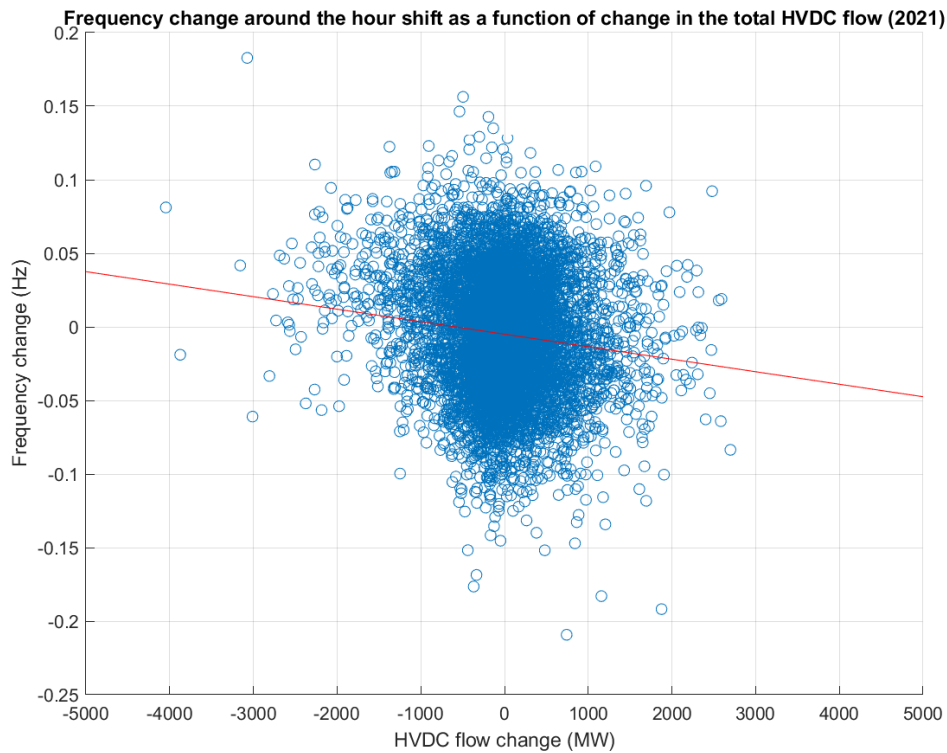


Figure 8: Scatterplot image of the average frequency changes around the hour shift as a function of changes in the hourly HVDC transmission between the Nordic synchronous system and other synchronous systems in 2021. *HVDC transmission data: Fingrid. Frequency data: Fingrid open data [36].*

Based on the analysis it can be concluded that the volumes of the hourly changes in the total Nordic production correlate with the frequency deviations at the hour shift. If the hourly production values vary significantly, the production changes at the hour shifts can be expected to be larger and faster despite the current production ramping restrictions. High production ramping can result in momentary imbalances and frequency deviation at the hour shift. However, the dependency between the volume of change in the Nordic production and the frequency deviation around the hour shift is not perfect since many other factors such as the speed and the volume of change in HVDC transmission and consumption along with other stochastic events affect the imbalances.

Although the current ramping restrictions for the production have been in use since 2013, the efficiency of the ramping restrictions for reducing the hour shift imbalances has not been thoroughly studied. Assessment of the efficiency of ramping restrictions in the Nordic synchronous system provides analysis of the economic impacts of applying the restrictions but the effect of the ramping restrictions on the imbalances at the hour shift is not evaluated on a practical level [5].

Calculating how much the current production ramping restrictions have reduced the hour shift imbalances is difficult. Directly comparing the effects of production ramping on the hour shift imbalances before and after applying the ramping restrictions would require accurate minute-resolution measurement data of the production in the Nordic synchronous system. There is, however, no convenient access to such data. Moreover, confirming the dependency between the hour shift imbalances and the production changes is anything but straightforward. Consequently, it is out of the scope of this thesis to assess how much the current ramping restrictions have improved the frequency quality at the hour shifts compared to a situation without the restrictions. However, based on the analyses conducted in this chapter, it can be confirmed that the current production ramping restrictions do not perfectly mitigate the frequency deviation at the hour shift caused by the production ramping.

3.2 Imbalances and production changes in 15-minute ISP

The introduction of the 15-minute ISP and the quarterly intraday, day-ahead, and balancing markets will significantly impact the balancing of the Nordic synchronous system. When the 15-minute ISP and the quarter-hourly imbalance pricing are introduced, the BRPs must settle quarterly imbalances instead of the current hourly imbalances. Addressing the quarterly imbalances will both decrease the total structural imbalances and reduce the peaks of the structural imbalances at the hour shift caused by the fast-ramping production.

The reduction in the total structural imbalances after the introduction of the 15-minute ISP and the quarterly intraday and balancing energy markets can be explained by the reduction in the netted imbalances. Currently, if the BRP has created equal amounts of surplus and deficit imbalance over the hour, the net imbalance is zero, although in practice the BRP would have been in imbalance for the whole hour. When the 15-minute ISP is introduced, the BRPs must address imbalances that would have been netted over the hour in the hourly ISP. This reduces the structural imbalances. The BRPs can naturally choose whether to balance their portfolio by trading in the 15-minute intraday and day-ahead markets, or to face the imbalance settlement cost and let the TSOs balance the quarterly imbalances in the balancing energy market [32].

When assessing the impacts of the quarterly ISP on the power system imbalances, assumptions and simplifications must be made. In the analogy presented in this chapter it is assumed that the implementation of the 15-minute ISP and the quarterly MTU in the intraday, day-ahead, and balancing markets does not alter the consumption or the HVDC transmission. In terms of HVDC transmission, the assumption is made just to simplify the analysis. The HVDC flows will probably change substantially after the introduction of the 15-minute ISP and the quarterly cross border electricity markets, but addressing those changes is out of the scope of this thesis. Assuming that the consumption is not affected by the quarterly ISP and the 15-minute electricity markets should be more reasonable. The power system demand is strongly dependent on the consumers' daily routines bound to the working hours and nighttime [37]. Thus, the market changes do not necessarily completely change the demand behavior but will certainly have some degree of impact on it.

The balancing presented in Figure 9 is ideal meaning that the market participants have a perfect foresight on how the demand will behave and they also perfectly follow the underlying market structure. In real life, perfect balancing could not be achieved because the production plans are based on the forecasted consumption and the mFRR activation is also based on different forecasts [8]. Moreover, even if the forecasts were perfect, there would still be physical limitations for the ramping of the production and the mFRR.

Figure 9 illustrates how the balancing of the power system before the activation of the automatic reserves would change if the 15-minute imbalances were perfectly balanced in the day-ahead, intraday, and balancing energy markets. The area between the production and the consumption curves represents the structural imbalances caused by the underlying market structure. As can be seen by comparing the upper and lower plots, the sum of the structural imbalances after the day-ahead and intraday markets and the mFRR regulation is smaller in the 15-minute ISP than in the hourly ISP.

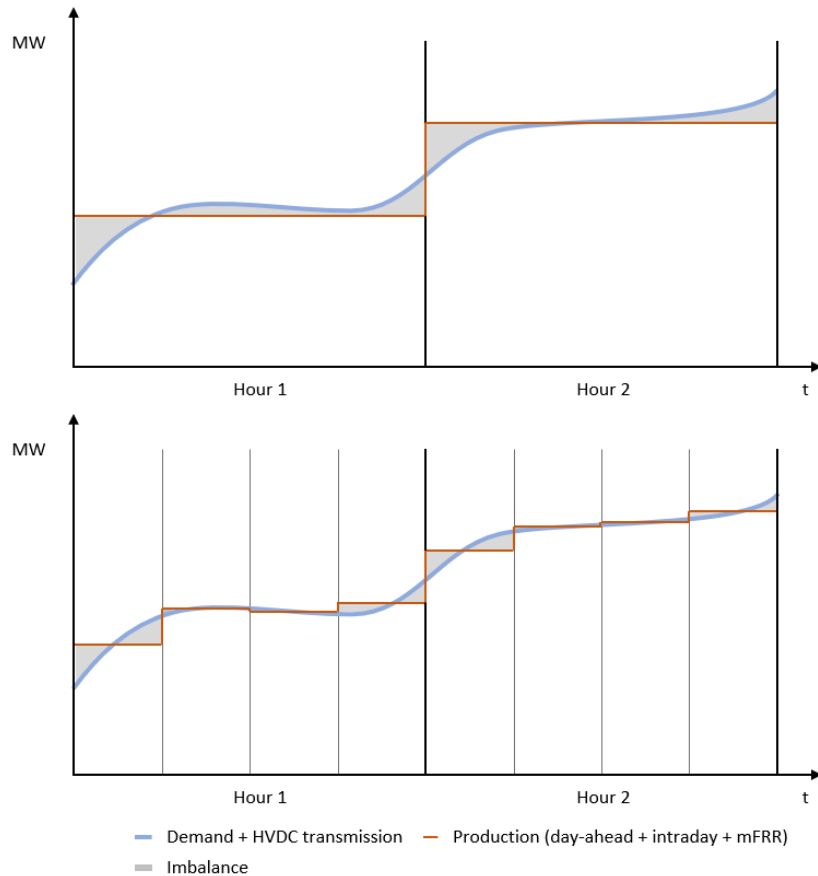


Figure 9: An illustration of the effects of the 15-minute ISP and the quarterly day-ahead, intraday, and balancing energy markets on the structural imbalances before the activation of the automatic reserves.

As Figure 9 illustrates, the greatest imbalances occur at the MTU shifts because of the fast production ramping. Even though the ramping of production is more moderate in real life, it is evident that the production ramping at the hour shift tends to be faster than the ramping of the demand and the HVDC transmission [1]. The 15-minute ISP allows the production to follow the demand more accurately. Essentially, the consumption has less time to change between the quarterly ISPs than between the hourly ISPs. As a result, the production changes at the hour shift are also reduced. However, instead of one ramping period at the hour shift, there will be four ramping periods at the 15-minute MTU shifts which is challenging for the system operation [38].

It is essential to address that the MTU shift production ramps are very much dependent on how the consumption and the HVDC transmission change over the course of the hour and the day. Substantial changes in the demand result in substantial production ramping that exceeds the demand after the hour shift [38]. If the MTU shift production ramping in the 15-minute ISP still is faster than the ramping of the demand, imbalances are likely

to occur especially when the production must ramp large volumes to keep up with the changes in the demand.

In the analogy presented in Figure 9, the balancing over the ISP is ensured in the day-ahead, intraday, and balancing energy markets. The TSOs aim to balance out the remaining imbalances by activating automatic reserves. Whether the imbalances can be balanced out depends on how fast and large the changes in the imbalance volumes are [32]. In the real power system also the ramping of the mFRR affects the volume of the imbalances before the activation of the automatic reserves. Figure 10 illustrates the hour shift production change in two different market situations. Ideally, both situations would result in the same balancing result but in reality, the speed and the volume of the mFRR activation affects the balancing.

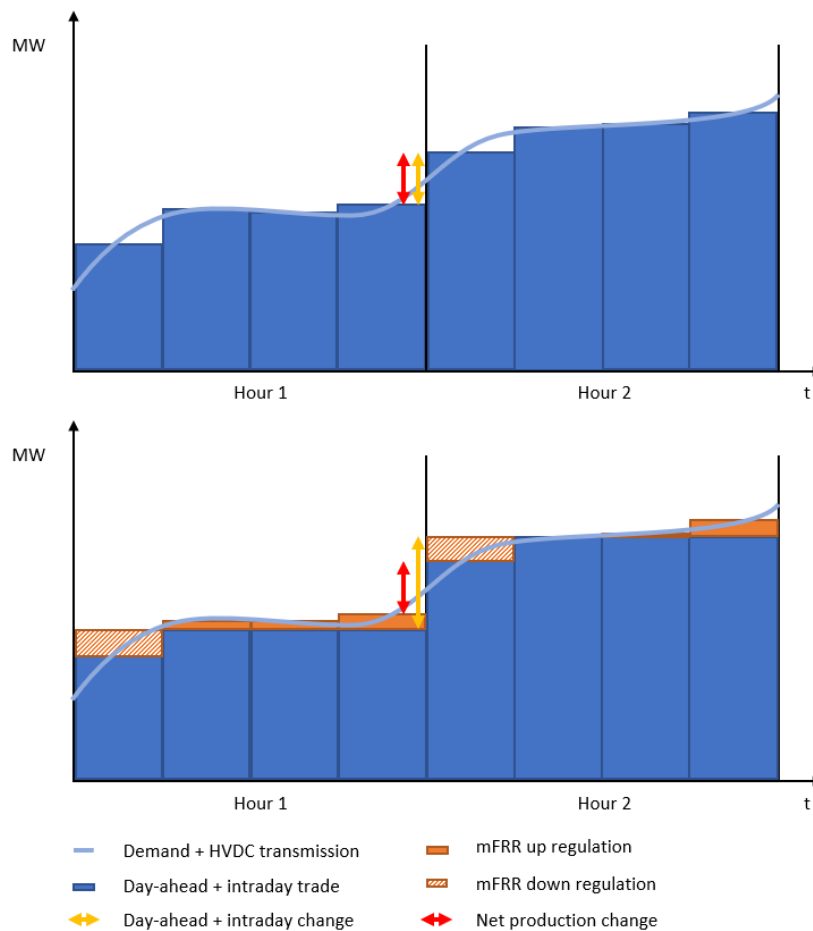


Figure 10: Upper plot: Hour shift production ramping in a situation where the quarterly imbalances are balanced completely by the BRPs in the day-ahead and intraday markets. Lower plot: Hour shift production ramping in a situation where the quarterly imbalances are balanced completely by the TSO in the balancing energy market.

If the BRPs decide to trade away their quarterly imbalances in the day-ahead and intraday markets the volume of the production change at the hour shift caused by the day-ahead and intraday trade is as illustrated in the upper plot of Figure 10. In theory, there is no need for mFRR activation. The remaining imbalances are balanced out by activating automatic reserves.

On the contrary, if the quarterly imbalances are not addressed in the day-ahead and intraday markets, the quarterly balancing is ensured by the up and down regulation of mFRR. As the lower plot of Figure 10 illustrates, the mFRR needs to ramp down at the hour shift to compensate for the large up-ramping caused by the day-ahead and intraday trade. In this scenario the imbalances at the hour shift very much dependent on how well the ramping of the mFRR counteracts for the ramping of the intraday and day-ahead trade. If the mFRR cannot keep up with the change in the production, the imbalances at the hour shift can be larger than they would be when the quarterly balances are addressed completely in the day-ahead and intraday markets. This would also result in more imbalances to balance with automatic reserves and ultimately more residual imbalances that cannot be addressed by activating reserves.

The two scenarios presented in Figure 10 are extreme cases. In reality, it is likely that some of the quarterly imbalances will be addressed in the intraday and day-ahead markets and the rest of the imbalances are addressed by the BRPs in the balancing energy market. Before transitioning to the quarterly day-ahead market, the ISP and the intraday market will move to 15-minute resolution. When the day-ahead market still operates in hourly resolution it is probable that the production changes at the hour shift are larger than the production changes at the other MTU shifts. After the introduction of the quarterly day-ahead market the hour shift are in principle no different to the other MTU shifts.

3.2.1 The volume of imbalance changes

The changes in the hour shift imbalances before the reserve activations are estimated in a cost-benefit analysis made on the effects of the 15-minute ISP and the quarterly intraday market [32]. Since the analysis discusses the imbalances before the reserve activations and not the final residual imbalances, the BRPs' commitment to trade away the quarterly imbalances directly affects the imbalance volumes and the volumes of the imbalance changes at the MTU shifts. As discussed in the previous chapter, the balancing over the ISP does not ideally depend on whether the balancing is done in the balancing energy market or in the intraday and day-ahead market. However, in a real power system the amount of intraday and day-ahead production ramping affects the amount of needed manual and automatic reserve activation and ultimately the volume of the residual power system imbalances.

The base assumption in the analysis [32] is that the 15-minute MTU does not affect the average hourly imbalances of the original imbalance data. In the analysis the traded 15-minute imbalances are calculated in relation to the 60-minute imbalances. Effectively this means that the volume of the average 60-minute imbalance is added to the calculated imbalance volume after the quarterly balancing, as can be derived from Equation 8. If 100 % of the quarterly imbalances were corrected in the intraday market, the traded volume of the 15-minute imbalances relative to the 60-minute imbalances would be:

$$\begin{aligned} \text{traded } 15\text{min imbalances}_{ideal} = & \quad (6) \\ \text{average imbalance}(15\text{min}) - \text{average imbalance}(60\text{min}) \end{aligned}$$

However, the analysis acknowledges that all the imbalances cannot be corrected in the intraday market. Therefore, the true volume of the traded imbalances used in the analysis is assumed to be 50 % from the ideal traded imbalances, unless stated otherwise.

$$\text{traded } 15\text{min imbalances} = 50 \% * \text{traded } 15\text{min imbalances}_{ideal} \quad (7)$$

The minute-by-minute imbalances after the introduction of the 15-minute ISP are then calculated by subtracting the traded imbalances from the original system imbalances.

$$\begin{aligned} \text{imbalances}_{15\text{minISP}} = \text{imbalances}_{orig} - 50\% * & \quad (8) \\ (\text{average imbalance}(15\text{min}) - \text{average imbalance}(60\text{min})) \end{aligned}$$

The imbalance jump at the hour shift is calculated by subtracting the imbalance value of the first minute of the hour from the imbalance value of the last minute of the previous hour. The percentage of the reduction in the imbalance jump at the hour shift is calculated as the difference between the average imbalance jump for imbalances_{orig} and $\text{imbalances}_{15\text{minISP}}$. According to the analysis, the largest 25 % of the imbalance jumps at the hour shift are reduced by 32 % after the introduction of the 15-min ISP. The smallest 25 % of the imbalance jumps are reduced by 23 %.

Since the base assumption in the analysis is that the 60-minute average imbalances are not affected by the introduction of the 15-min ISP, the reduction in the average imbalance for the whole assessment period is rather modest. Depending on the market parties' commitment to trade away the quarterly imbalances, the reduction in the average imbalances is 3-6 %.

Whether the average 60-minute imbalances are affected by the 15-minute ISP and the quarterly markets, is a question of debate. There is always a certain amount of stochasticity in the imbalances that cannot be predicted in advance. However, it could be argued that the structural imbalances caused by the inability to address the sub-hour imbalances in the hourly ISP could

be addressed in the 15-minute ISP to an extent that would also reduce the average 60-minute imbalances.

One shortcoming of the analysis is the way the imbalance changes at the hour shift are calculated. The hour shift ramping of production, consumption and HVDC transmission can vary depending on the ramping decisions of individual parties. Due to this, the largest change in the system imbalance does not necessarily occur exactly at the hour shift but rather slightly before or after the hour shift. However, the analysis only calculates the imbalance change between the last minute of the previous hour and the first minute of the last hour. Due to this, there might be imbalance changes happening around the hour shift that are not addressed in the analysis.

3.3 Hydropower production ramping

Hydropower is one of the main electricity production types in the Nordic synchronous system. In 2019, over half of the total electricity consumption in the Nordic synchronous system was covered with hydropower production [39]. According to Nordic grid development perspective, the combined hydropower capacity of Finland, Sweden, Norway, and Denmark in 2020 was approximately 52 GW. The report estimates that in 2030 the installed hydropower capacity will be around 57 GW [40]. Compared to the capacity growth of wind or solar power production, the growth of hydropower capacity is more modest.

As mentioned in Chapter 2.3.2, the production ramping restrictions affect all BRPs but currently mainly the largest BRPs with hydropower assets are restricted by the rules since they are capable of ramping large volumes of power in a relatively short time. To get an understanding of the significance of hydropower ramping, the changes in the hourly Nordic hydropower production are analyzed in this chapter. First, it is evaluated to what extent the changes in the total Nordic production are caused by the changes in the Nordic hydropower production. Second, it is analyzed how the hourly changes in the Nordic hydropower production affect the power system frequency.

Figure 11 has three plots representing the hourly production changes in 2021. The changes are calculated by subtracting the production value of the previous hour from the production value of the next hour. The first plot shows the hourly changes in the total Nordic production and the second plot shows the hourly changes in the Nordic hydropower production. The first two plots look very similar indicating that there is a strong positive correlation between the changes in the total Nordic production and the changes in the Nordic hydropower production. The third plot illustrates the remaining production changes when the hydropower production changes are subtracted from the total production changes i.e., the hydropower production changes are assumed to be zero.

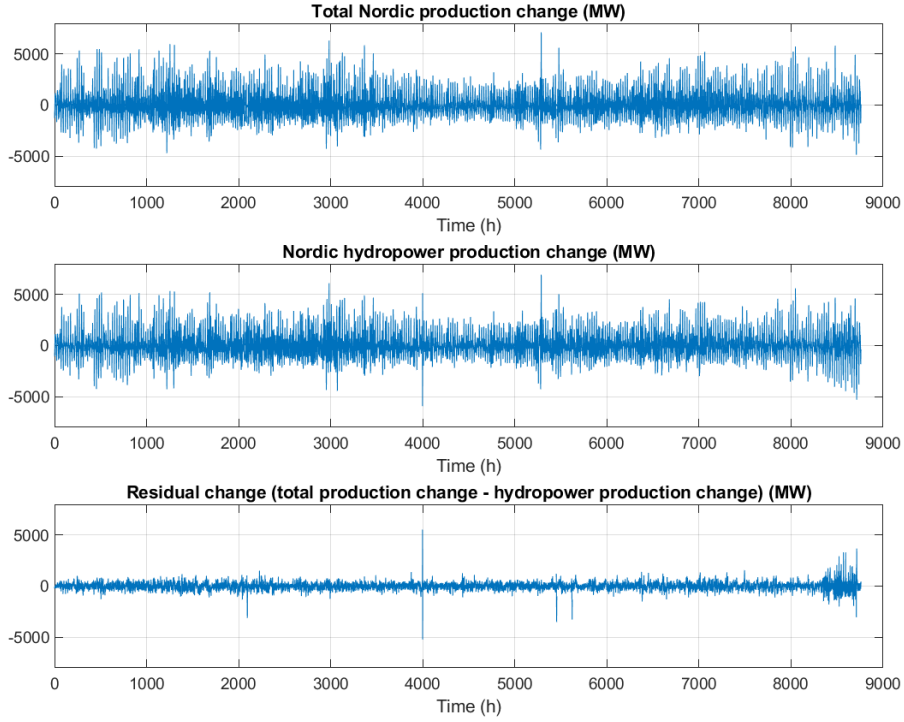


Figure 11: Hourly production changes in the Nordic synchronous system in 2021. *Production data: Nord Pool [35]. Hydropower production data: Fingrid.*

Equation 9 expresses the share of residual changes from the total production changes in 2021. According to the calculation, the remaining production changes only account for approximately 30 % of the summed absolute changes in the total Nordic production. Conversely, it can be approximated that about 70 % of the summed absolute changes in the total Nordic production are caused by the hydropower ramping.

$$\frac{\sum_{i=1}^n |\Delta P_{total_i} - \Delta P_{hydro_i}|}{\sum_{i=1}^n |\Delta P_{total_i}|} * 100 \% = 29.05 \dots \approx 30 \% \quad (9)$$

Based on the analysis it can be stated that a substantial part of the changes in the total Nordic production is caused by the hydropower ramping. Although the growth in the Nordic hydropower capacity is rather small, the existing hydropower production is the single largest contributor to hourly production changes.

The effects of the hydropower ramping on the power system frequency are evaluated in Figure 12 by plotting the frequency change at the hour shift as a function of change in the hourly Nordic hydropower production. The frequency change is calculated as a change in the average frequency 5 minutes before and 5 minutes after the hour shift. Positive change in the frequency

means that the frequency has increased at the hour shift and vice versa. The principle of the analysis is the same as for Figures 7 and 8 in Chapter 3.1.

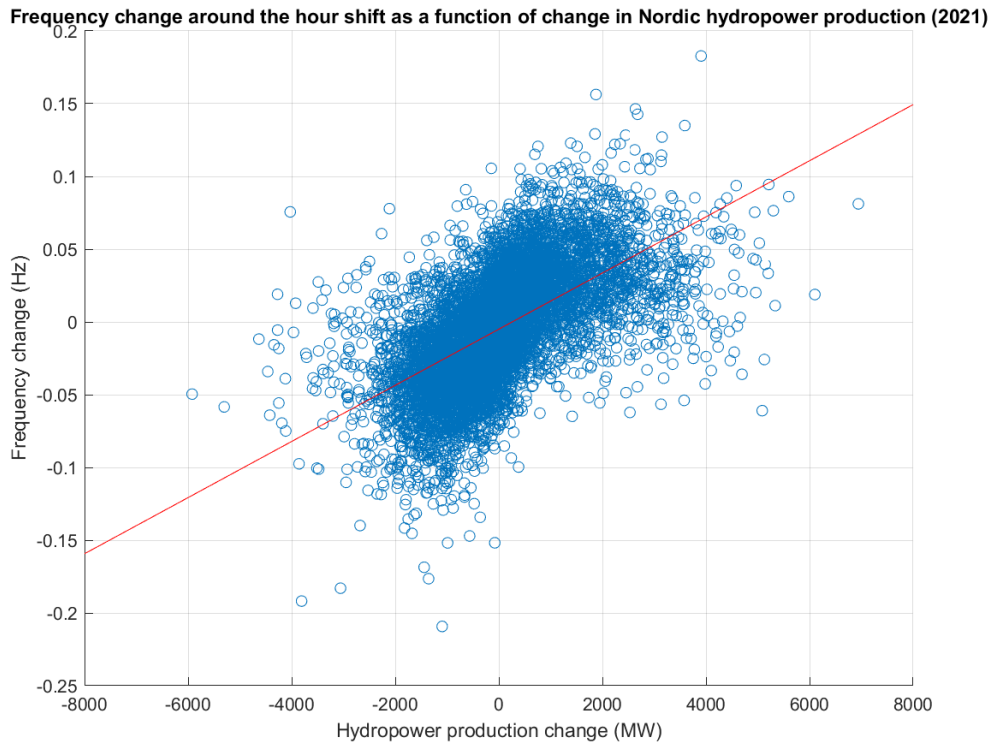


Figure 12: Scatterplot image of the average frequency changes around the hour shifts as a function of the changes in the hourly Nordic hydropower production in 2021. Red least squares regression line gives a rough linear estimate of the dependency between the two variables. *Hydropower production data: Fingrid. Frequency data: Fingrid open data [36].*

As can be seen from Figure 12, the frequency changes around the hour shifts are dependent on the changes in the hourly Nordic hydropower production. The calculated correlation is 0.6. The changes in the hourly Nordic hydropower production correlate, in fact, more with the hour shift frequency deviations than the changes in the total Nordic production illustrated in Figure 7. If the changes in the Nordic hydropower production are assumed to be zero, the residual changes do not significantly correlate with the hour shift frequency changes.

As with the similar analysis made for the changes in the total production in Chapter 3.1.1, the frequency changes at the hour shift cannot be completely explained by only studying the changes in the hourly production volumes. More accurate data of the production is required to assess how the hydropower production is ramping at the hour shift. However, based on the analysis it can be confirmed that hydropower is a significant contributor to the hour shift imbalances despite the current production ramping restrictions.

In spite the negative impacts on the system frequency, the hydropower production is also likely to remain as the main source of flexibility in the future power system. According to Nordic grid development perspective 2021, the need for flexible hydropower production will even increase in the future Nordic power system as more and more intermittent generation is introduced in the system [40].

3.3.1 Future view of hydropower production ramping

A significant factor affecting the hydropower production ramping in the future is the introduction of the 15-min ISP and the quarterly intraday and day-ahead markets. As discussed in Chapter 3.2, the production changes at the MTU shifts can be expected to reduce when the quarterly ISP is introduced. The effects of the 15-minute intraday and day-ahead markets on the changes in the hydropower production are very much dependent on the market participants' commitment to trade in the markets in question. The more the BRPs are willing to balance their 15-minute imbalances, the more the hour shift production changes before the reserve activations are reduced.

Chapter 3.2.1 presents the analysis made on the effects of the 15-minute ISP on the power system imbalances [32]. Although the analysis discusses the changes in the imbalance values before the reserve activations, it can also provide insight on how the production ramping comprising of mostly hydro power ramping is affected by the introduction of the 15-min ISP and the quarterly intraday market. If the consumption changes and the HVDC ramping are assumed insignificantly slow compared to the production ramping, the production ramping equals to the imbalance jumps discussed in the analysis. Thus, some rough estimates of how much the production ramps are reduced can be done based on the analysis.

Although some rough estimates can be made, it is very difficult to know exactly how the hydro power production ramping will change when the 15-minute ISP and the quarterly intraday and day-ahead markets are introduced. The BRPs' willingness to balance their quarterly imbalances depends on how lucrative it is to trade in the intraday and day-ahead markets compared to trading in the balancing energy market and other balancing markets. According to the analysis, the market participants may find it more profitable to trade in the intraday market because the cheaper, slow-ramping assets can be utilized. In the balancing energy market, the requirements for the response time for the delivery can limit the use of the slow-ramping assets. Another reason for the increased intraday trade is that there is no uncertainty in the power delivery whereas in the balancing energy market the market participants cannot know whether their bids will be activated and for how long [32].

There are uncertainties related to the need of restricting hydropower ramping in the future. Large changes in the production around the MTU

shifts are not guaranteed to disappear even after the introduction of the 15-minute day-ahead market because the production is planned based on the demand. If the changes in the demand are substantial, the production changes must be also large. Therefore, the higher market resolution does not necessarily completely mitigate the momentary imbalances at the MTU shifts.

3.4 Wind power production ramping

The share of wind power capacity in the Nordic power system is increasing rapidly. In the end of 2020, the combined wind power capacity of Finland, Sweden, Norway, and Denmark was 22 738 MW. In the end of 2023, the expected Nordic wind power capacity is around 36 700 MW meaning that the capacity would grow by approximately 60 % in three years [41]. In September 2021, the amount of unsubsidized wind power under construction in Finland alone was 3318 MW, with most of the power plants coming online in 2022 and 2023. Thus, the amount of wind power in Finland can be expected to more than double from the 2020 value till the end of 2023 [42]. Nordic grid development perspective estimates the amount of Nordic wind power in 2030. In the climate neutral Nordic scenario, the amount of wind-power is expected to be 60 000 MW in 2030 [40].

The rapid increase in wind power capacity poses challenges to the Nordic power system in terms of varying and intermittent power output. Wind power production is dependent on the wind that varies both spatially and temporally [43]. The production of a single wind turbine or a wind farm can vary substantially. However, aggregated production from a large geographical area smooths out the variations in the power output [44].

The variability of the wind power production decreases when the variations are measured over shorter time [45]. For instance, the variability of wind power is higher for hourly variations than for 15-minute variations. Research states that fast minute-scale variations in the wind power output are usually insignificantly low and have no effect on the power system operation. However, in-hour variations in the timescale of 10-60 minutes can be much more significant and the maximum power ramps can be up to 50-60 % of the capacity. Hourly variations during the day greatly affect scheduling the power production and commissioning the reserves [44].

Although natural variations of wind power output can be substantial and require planning of the power system operation, this thesis focuses on the production ramping at the shift of the MTU. Whereas the conventional production must ramp at the shift of the MTU to keep producing according to the plan, the ramping of wind power mainly depends on the wind conditions. However, in some cases the changes in the market price of electricity can cause the wind power to ramp at the MTU shift.

Since the marginal costs of wind power production are very low, it is usually more beneficial to produce wind power than to shut down the production even when the electricity prices are low [46]. However, occasionally the day-ahead price of electricity can turn negative which forces the producers to pay for generation. This can incentivize the wind power producers to completely shut down their production for the hours of negative day-ahead prices which results in fast down ramping of wind at the hour shift. Similarly, the changes from negative day-ahead prices to positive day-ahead prices can cause the production to ramp up rapidly. Ramping of wind power caused by negative day-ahead prices (hereafter price-induced wind power ramping) can be substantial in both volume and speed.

Although negative day-ahead prices can be considered as the first requirement for the price-induced wind power ramping, multiple factors affect the ramping decision of the BRPs. One of the most important factors is the wind power production subsidies. In Finland, wind power plants built in 2012-2019, approximately 2200 MW, receive feed-in tariff [47]. In principle, these power plants would ramp down only after the negative day-ahead price exceeds the financial benefit given by the feed-in tariff. Wind power plants built after 2019 do not receive feed-in tariff. Consequently, these power plants are more likely to ramp down their production as the day-ahead price turns negative. Different subsidy systems are used in different countries of the Nordic synchronous system, and they have a significant impact on the ramping decision.

The profitability of the wind power production also depends on many other factors such as the PPA agreements between the wind power producers and consumers, the intraday and balancing market prices, the prevalence of the negative day-ahead prices, the volume of the negative day-ahead prices and the operating and maintenance costs of the wind power plants [47]. Since the financial incentives for the price-induced wind power ramping can vary, it is very difficult to predict how the individual plants will behave during negative day-ahead prices.

Chapter 3.4.1 provides more information about the price-induced ramping in the Nordic synchronous system and aims to assess how common the price-induced ramping has been in the recent years. Based on the assessment, future aspects of price-induced wind power ramping are discussed in Chapter 3.4.2.

3.4.1 Price-induced ramping of Nordic wind power

Negative day-ahead prices have multiple times caused the wind power production to ramp in the Nordic power system and individual cases of price-induced ramping have been reported by the Nordic TSOs. Imbalance reports made by the Finnish TSO Fingrid report price-induced wind power ramping volumes of 500-600 MW in Finland. The reported speed of change in the

total Finnish wind power production has been dozens of megawatts per minute [6, 48]. According to email discourse with the Danish TSO Energinet, in Denmark cases of price-induced ramping have been reported where the maximum one-minute average down-ramping speed for an individual 400 MW wind farm has been 186 MW/min and 304 MW/min for up-ramping.

Modern wind turbines equipped with blade pitch control can ramp up from the lowest rated power output to the highest power output in 6-10 seconds if there is enough wind resource. Some manufacturers even report response times of 1-2 to 4-6 seconds for up and down regulation for individual wind turbines. However, on a wind farm level the regulation is somewhat slower, from 10 to 20 seconds [49].

On a power system level, the speed and the volume of price-induced wind power ramping is naturally affected by the number of the ramping wind power plants and the size of the plants. Multiple wind power plants ramping down or up at the same hour shift can result in larger ramping volumes, but the ramping speed naturally depends on how simultaneously the individual plants are ramping. For example, two identical 400 MW plants ramping at the same hour shift would not necessarily result in doubled ramping speed unless the power plants started ramping at the exact same moment.

There are no reported cases of price-induced wind power ramping directly affecting the Nordic power system balance but according to an internal imbalance report made by Fingrid price-induced wind power ramping has been a partial reason for a frequency deviation occurring on 5 April 2021. According to the report, 600 MW of Finnish wind power production ramped down at the hour shift when the day-ahead price turned negative at 2.00 am Finnish time. Wind power producers had made changes to their production plans earlier in the evening, but the changes were not registered by the TSOs which resulted in frequency deviation at the hour shift when the wind power producers ramped down their production [48]. However, whether the wind power ramping was the only cause for the frequency deviation, can be argued.

Figure 13 shows the frequency deviation and the down-ramping of wind power production discussed in the imbalance report. It can be seen from the figure that the Nordic synchronous system frequency has dropped down to 49.79 Hz the same time the Finnish wind power production has ramped down. The volume of the wind power ramping occurring simultaneously with the frequency deviation is approximately 450 MW. According to the measurement data of total Finnish wind power production, this main ramping has lasted for 6 minutes, starting two minutes before the hour shift, and ending four minutes after the hour shift.

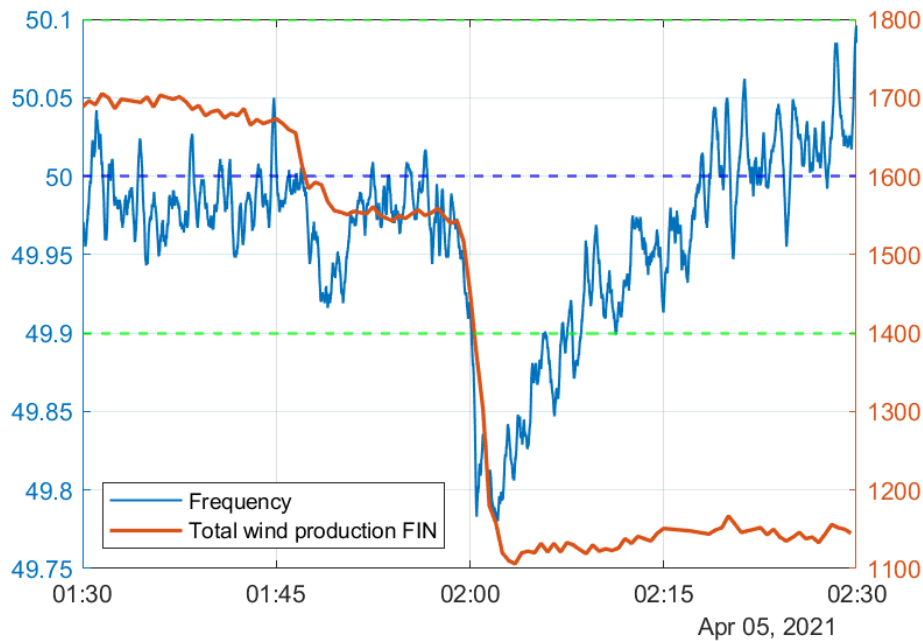


Figure 13: Nordic synchronous system frequency (Kangasala PMU) and Finnish wind power production at the hour shift from negative to positive day-ahead prices on 5 April 2021. *Wind power production data: Fingrid. Frequency data: Fingrid.*

If there are no major errors in the measurement data, the Finnish wind power production ramping is very unlikely to have been the only cause for the frequency deviation on 5 April 2021. As the simulations in Chapter 4 aim to prove, under 49.8 Hz frequency deviation would require substantially faster ramping time or larger ramping volume than what was measured. Furthermore, it can be seen from the figure that the frequency deviation reaches its local minimum several minutes before the wind power production reached its minimum, which suggests that the frequency deviation is caused by something else than the wind power ramping. In addition to the Finnish wind power ramping, down-ramping of wind occurred also in Sweden where the main ramping was approximately 540 MW in 11 minutes. However, the ramping occurred already before the hour shift and the major frequency deviation. It is worth to note that the data of the Swedish total wind power production is partially estimated, and the numbers may differ from real values.

The true cause for the deviation at the hour shift on 5 April 2021 remains unclear. Wind power ramping is likely a partial reason for the deviation as the TSOs were not prepared for the ramping. However, the magnitude of the frequency deviation suggests that there has been also some other source of power system imbalance at the hour shift. Sudden changes in the production, in the HVDC flows, or other power system faults might have caused the frequency to deviate.

As discussed in Chapter 2.3.1, if the production plan of a BRP changes more than 200 MW at the hour shift, the BRP needs to provide the TSOs with quarterly production plans. By examining the production plans of the Finnish BRPs responsible of the wind power ramping on 5 April 2021 it can be noted that two BRPs should have rescheduled their production at the hour shift. However, no quarterly production plans were provided. If the BRPs had followed the ramping restrictions the production change at the hour shift would have likely been much smaller.

In addition to 5 April 2021, there have been three other cases when the day-ahead price has turned from positive to negative in Finland. Figure 14 shows how the system frequency and the wind power production have behaved during those hour shifts. As can be observed from the figures, the ramping volumes and the ramping times are very different in each case. In Figure 14 a) 500 MW of wind power production has ramped down at the hour shift, but the ramping time is almost 15 minutes. Figure 14 b) shows no down-ramping of wind power whatsoever. In Figure 14 c) wind power production has ramped down relatively fast, but the volume of the ramp is only 200 MW. Figure 14 d) is the same as Figure 13. Apart from Figure 14 d) the other figures show no major frequency deviation at the hour shift.

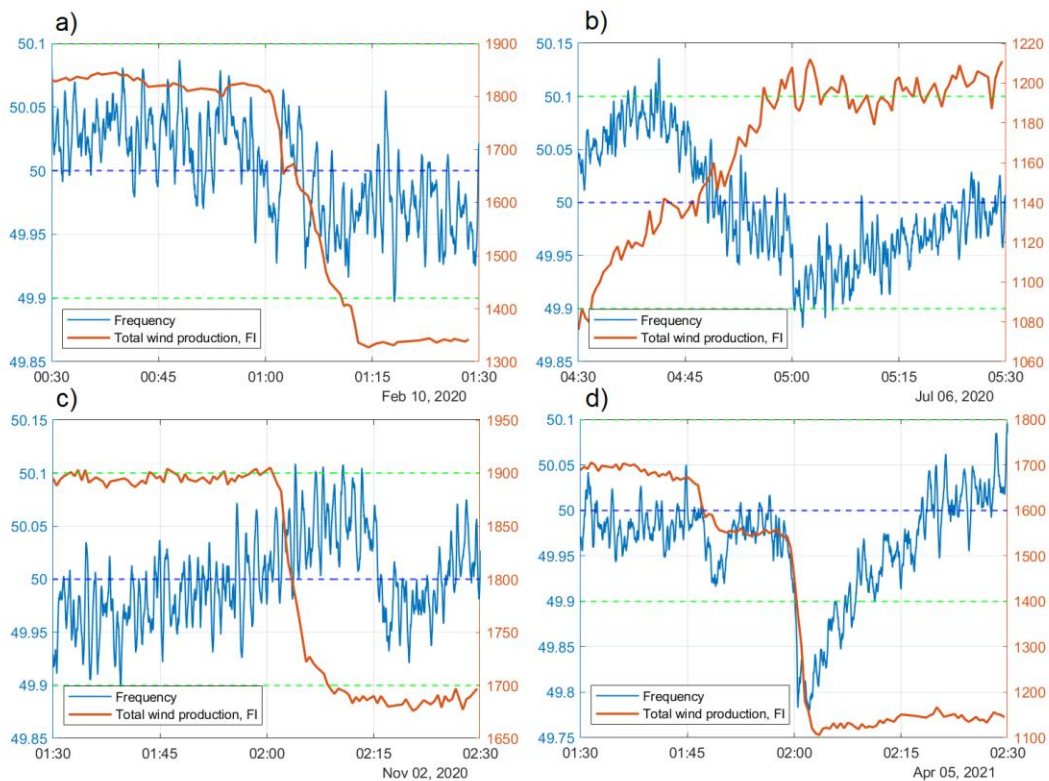


Figure 14: Hour shifts from positive to negative day-ahead prices in Finland. Price-induced wind power ramping can be noted in subplots a), c) and d). Frequency has deviated in subplot d). *Wind power production data: Fingrid. Frequency data: Fingrid.*

Comprehensive study of the price-induced ramping of wind power is difficult to carry out on a Nordic power system scale as it would require access to accurate measurement data of the wind power production in the whole Nordic synchronous system. Due to the poor accessibility and quality of the data, it is out of the scope of this thesis. However, estimations of how common the price-induced wind power ramping has been in the recent years can be done by studying the occurrences of the negative day-ahead prices in the Nordic synchronous system. As discussed in the previous chapter, the negative day-ahead prices do not always cause the wind power to ramp, but they can be considered the first condition for the price-induced wind power ramping. Thus, the theoretical number of possible hour shifts for price-induced wind power ramping can be counted from the hourly data of day-ahead prices in the Nordic synchronous system.

Table 2 shows the number of hour shifts when the day-ahead price has turned from positive to negative or from negative to positive in one or several price areas of the Nordic synchronous system. The number of hour shifts from positive to negative day-ahead prices gives the theoretical maximum number for the possible hour shifts for the price-induced down-ramping of wind. Similarly, the number of hour shifts from negative to positive day-ahead prices gives the theoretical maximum number for the possible hours shifts for the price-induced up-ramping of wind.

Year	Number of hour shifts from positive to negative day-ahead prices	Number of hour shifts from negative to positive day-ahead prices
2019	25	25
2020	20	20
2021	7	8

Table 2: Number of hour shifts when the day-ahead price has turned from positive to negative or vice versa. *Day-ahead market data: Nord Pool* [35].

In Table 3 the possible hour shifts for price-induced wind power ramping are further categorized based on the crossings of the standard frequency range after the hour shift. If one or more samples in the 1 second frequency data has crossed the lower limit of standard frequency range 0-10 minutes after the potential hour shift for down-ramping of wind, under 49.9 Hz deviation is reported. Likewise, if one or more samples in the 1 s frequency data has crossed the upper limit of standard frequency range 0-10 minutes after the potential hour shift for up-ramping of wind, over 50.1 Hz deviation is reported.

Year	Potential hour shifts for down-ramping of wind	<49.9 Hz deviations	Potential hour shifts for up-ramping of wind	>50.1 Hz deviations
2019	25	7	25	2
2020	20	3	20	8
2021	7	3	8	4

Table 3: Number of possible hour shifts the for price-induced wind power ramping and the number of possible hour shifts after which the frequency has deviated under 49.9 Hz or over 50.1 Hz. *Day-ahead market data: Nord Pool [35]. Frequency data: Fingrid open data [36].*

Table 2 shows that in 2019-2021 there have been a few potential hour shifts for the wind power ramping after which the frequency has crossed the standard frequency range. Although the possible ramping and the frequency deviation have occurred at the same hour shift, there is a high possibility that the frequency deviation has not been caused by the wind power ramping. Furthermore, it is possible that no wind power ramping has occurred in the first place. For example, three crossings of 49.9 Hz in 2020 were not caused by wind power ramping. The negative day-ahead prices during those cases were experienced in eastern Denmark, but the 5-minute wind power production data in eastern Denmark shows no down-ramping of wind during the corresponding hour shifts.

Table 4 shows the total number of minutes outside the standard frequency range for the frequency deviations in Table 3. The numbers are based on the number of 1 second samples outside the standard frequency range 0-10 minutes after the hour shift.

Year	Time under 49.9 Hz (s)	Time over 50.1 Hz (s)
2019	539	46
2020	110	319
2021	711	227

Table 4: Theoretical time outside the standard frequency range caused by price-induced wind power ramping. *Day-ahead market data: Nord Pool [35]. Frequency data: Fingrid open data [36].*

Based on Table 4 it can be noted that even if the all the seconds outside the standard frequency range were, indeed, caused by wind power ramping, the time outside the standard frequency range caused by the wind power ramping would be insignificantly low compared to the yearly number of minutes outside the standard frequency range. For instance, in 2020 the total time outside the standard frequency range was 9561 minutes [50], and according to Table 3 the theoretical maximum time outside the standard frequency

range caused by price-induced wind power ramping was 429 seconds which accounts for 0.045 % of the yearly deviations.

3.4.2 Future view of price-induced wind power ramping

Understanding the role of price-induced wind power ramping in the current power system is crucial for making predictions of how the conditions might evolve in the future. Based on the analyses in the previous chapter, price-induced wind power ramping does not pose major risk for imbalances with the current production levels and electricity prices. However, the wind power capacity in the Nordic synchronous system is growing substantially in the near future which will affect both the incidence of the negative day-ahead prices and the volume and the speed of price-induced wind power ramping.

The increasing volume of variable renewable energy generation such as wind power production decreases the market price of electricity due to the merit order effect. When the supply of renewable generation is high, expensive conventional generation is driven out of the market. This is because of the low marginal cost of renewable production and the support mechanisms for the renewable generation [46].

During the times of low demand and high shares of renewable generation, the day-ahead price of electricity can turn negative. Part of the power system base load such as nuclear power production is inflexible and must make negative bids in the day-ahead market to avoid reductions in the power output. Negative day-ahead prices reflect the power systems inability to make use of the excess electricity i.e., the lack of downward flexibility. Support mechanisms such as wind power subsidies also artificially drive down the electricity price as producers receiving production benefits are willing to generate even when the electricity price is negative [46].

Based on the studies conducted in other European power systems [46, 51], it is likely that the rapid increase of wind power production will also lower the electricity prices in the Nordic synchronous system and increase the price volatility. If the downward flexibility of the Nordic synchronous system is not increased, the negative day-ahead prices will probably become more frequent. This can increase the number of potential MTU shifts for the price-induced wind power ramping.

Newly built wind power plants do not receive production subsidies which increases the likelihood of price-induced wind power ramping. Furthermore, the grant period for the subsidies for the previously built wind power plants will eventually end. On one hand this might decrease the volume of the negative day-ahead prices as the wind power producers would not be incentivized to make negative bids on the market, but on the other hand there would be even more wind power plants willing to shut down their production during hours of the negative day-ahead prices.

The volume and the speed of price-induced wind power ramping can be expected to increase in the future as more and more unsubsidized wind power production is introduced in the Nordic synchronous system. However, as the analysis in the previous chapter shows, the exact volumes and speeds are very hard to predict as the ramping decisions of the individual wind power producers can vary.

Whereas the volume of hydropower ramping and production ramping in general is heavily affected by the 15-minute ISP and the quarter-hourly markets, the volume of price-induced wind power ramping is not directly affected by the higher resolution ISP and electricity markets. It is evident from the analysis in the previous chapter that the threshold value of price-induced wind power ramping can be the same for a substantial volume of wind power production. Whether multiple wind power producers decide to ramp their production at the same MTU shift after the introduction of the 15-minute ISP and the quarterly markets is dependent on how the negative quarterly electricity market prices will form.

Although the exact nature of the price-induced wind power ramping in the future power system is hard to predict, the power system's response to production ramps can be simulated. Chapter 4 aims to find the threshold ramping values for production ramping in the Nordic synchronous system.

4 Simulation

This chapter simulates the effects of the production ramping on the power system balance. As discussed in Chapter 3, the volume of the structural imbalances at the MTU shift is affected by the volume of the production ramp and the ramping time. The deterministic imbalances at the MTU shift can be measured as frequency deviation. By simulating the impacts of different production ramps on the Nordic synchronous system frequency, it is possible to find how large and how fast the production ramps need to be to cause a certain amount of frequency deviation.

4.1 Model description

The model used in the study is a MATLAB Simulink model built for the project ‘Analysis & review of requirements for automatic reserves in the Nordic synchronous system’ carried out by the Nordic TSOs in 2011. The model was originally intended to represent the Nordic synchronous system as close as possible to analyze and develop the automatic reserves in the Nordic synchronous system [13]. For this study, some modifications were made to the reserve response of the model to get it to better represent the current situation in the Nordic synchronous system. However, the system reserves in the model are, for the most part, representative of the situation in 2011. This is important to address when interpreting the simulation results.

Figure 15 shows the high-level overview of the model. On the left side, the model input is presented as imbalance in MW. The imbalance is converted into frequency value in the ‘Rotating mass’ block which simulates the kinetic energy stored in the spinning generators of the power system. The ‘Self-regulation’ block simulates the self-regulation of the power system load, and it is added to the input signal. The ‘FCR’ block contains the modelled FCR-N and FCR-D reserves in each country of the Nordic synchronous system. ‘aFRR’ block represents the common Nordic aFRR response. Both the ‘FCR’ and the ‘aFRR’ blocks adjust the frequency based on how much the simulated frequency deviates from the 50 Hz setpoint frequency ‘fset’.

The country-specific characteristics of FCR-N and FCR-D such as the available reserve capacity, the types of the reserve providing units, and the governor settings are considered in the model. FCR capacity is mainly provided by hydropower units but in Denmark FCR-N is provided by thermal power plants.

The aFRR response is also included in the model. The centralized controller used for sending the aFRR activation signal to the Nordic countries is modelled and modified to better correspond with the current governor settings. The aggregated Nordic aFRR-response is modelled with a transfer function representing the response of the aFRR-providing hydro generators.

The acquired aFRR capacity is assumed to be 400 MW. FFR entities are not included in the model.

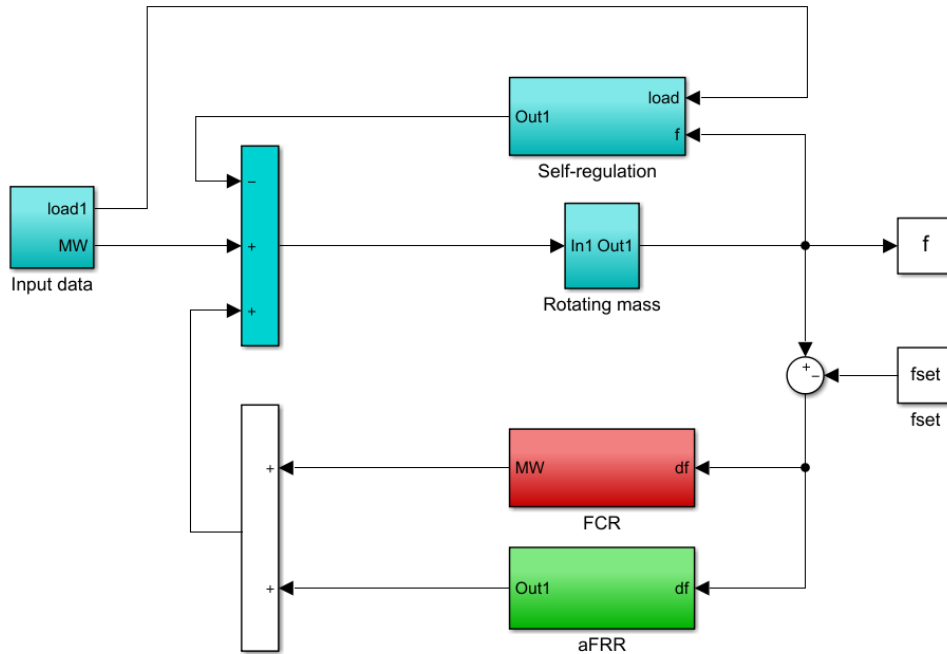


Figure 15: High level overview of the Simulink model representing the Nordic synchronous system and the automatic reserves.

In addition to the reserves, the model’s response to imbalances is affected by the of power system load and kinetic energy levels. As discussed in Chapter 2.1.2, the amount of load self-regulation depends on the amount of frequency-dependent load in power system. In the model the amount of load self-regulation is assumed to be 1%/Hz, meaning that if the frequency deviates 1 Hz the load will decrease or increase 1 %. Therefore, the self-regulating effect is greater for larger frequency deviations and for higher loads. As mentioned in Chapter 2.1.1, the amount of kinetic energy stored in the synchronous machines of the power grid affects how well the system can resist frequency deviations. The model allows simulations with different kinetic energy and load/generation levels.

4.2 Simulation of linear production ramping

A simple way to simulate the impact of the MTU shift production ramping on the power system balance is to feed the simulation model with linear imbalance ramps representing the aggregated MTU shift production ramping in the Nordic synchronous system. The model’s frequency response to the production ramps can be then studied. Although a linear production ramp might

not best describe the ramping of a single generator, it can be assumed that aggregating multiple ramping generators results in smoother linear-like production ramp.

Figure 16 shows how the modelled system frequency and the automatic reserves react to a linear imbalance ramp. 290 MW imbalance/production ramp starts at 10th second and ramps down in 30 seconds. This causes the system frequency to drop from 50 Hz close to the lower limit of the standard frequency range. The lowest plot shows how the system reserves react to the frequency deviation. FCR-N activates partially in a few seconds and in this case stops the frequency from deviating under 49.9 Hz. After some while, aFRR starts to activate and release FCR back into use.

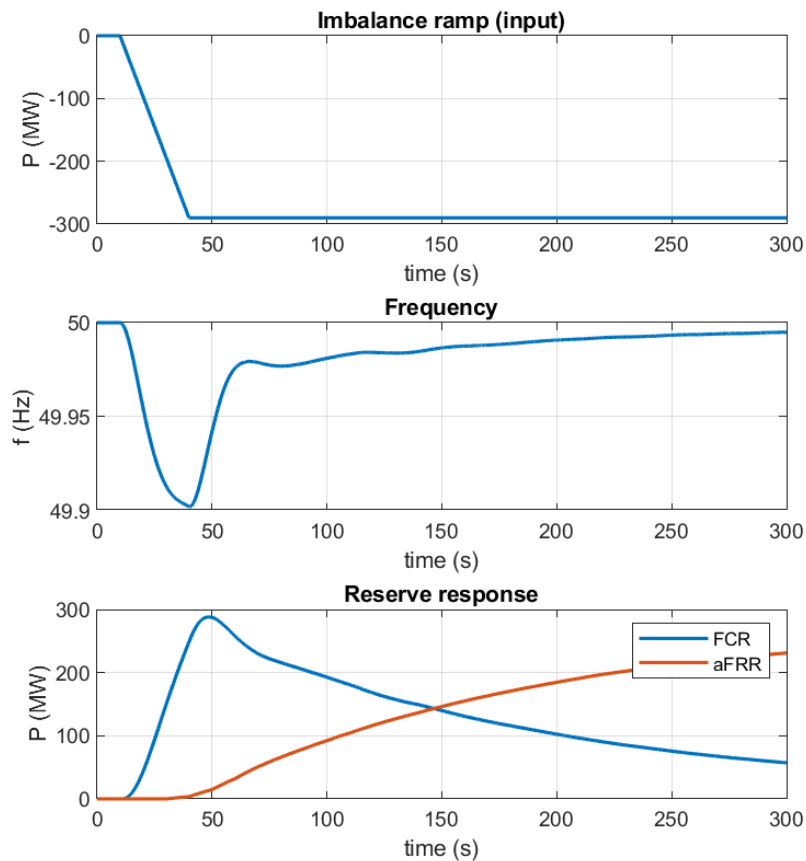


Figure 16: Modelled frequency and reserve response to a linear 30 second 290 MW imbalance ramp.

By running the simulation multiple times with different ramping times and ramp volumes it is possible to present the maximum frequency deviation as a function of the ramp volume and the ramping time. This results in a three-dimensional plane where the x and y axes represent the ramp volume and ramping time, and the z axis represents the maximum/minimum frequency

value after the production ramp. However, since 3-d plots are difficult to interpret, it is more informative to present how large the ramp volumes and the ramping times need to be for the frequency to deviate a certain amount. These ‘threshold ramping values’ can be represented as a two-dimensional graph.

Figure 17 illustrates the threshold ramping values for under 49.9, 49.8, and 49.7 Hz frequency deviations and Figure 18 presents the same for over 50.1, 50.2, 50.3 Hz deviations. The nominal frequency before the production ramp is 50 Hz in each case. As can be seen from the figures, the impact of the production ramping on the frequency deviation depends largely on the ramping time. For stepwise production changes, very low ramping volumes can cause the frequency to deviate considerably. On the other hand, when the ramping time is several minutes, increasing the ramp volume has less impact on the volume of the frequency deviation. The results look very similar for over and under frequency deviations.

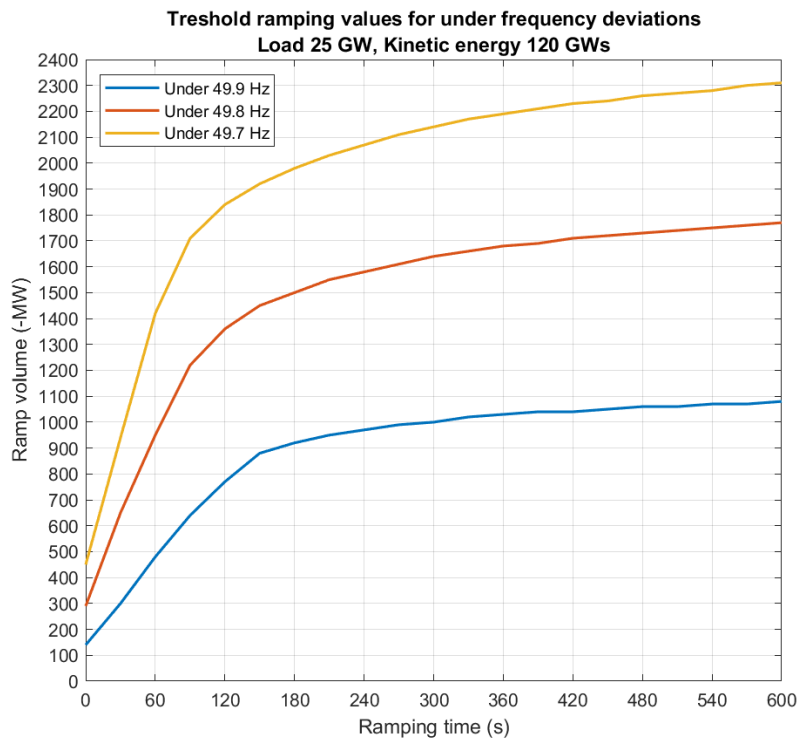


Figure 17: Threshold ramping values for under frequency deviations.

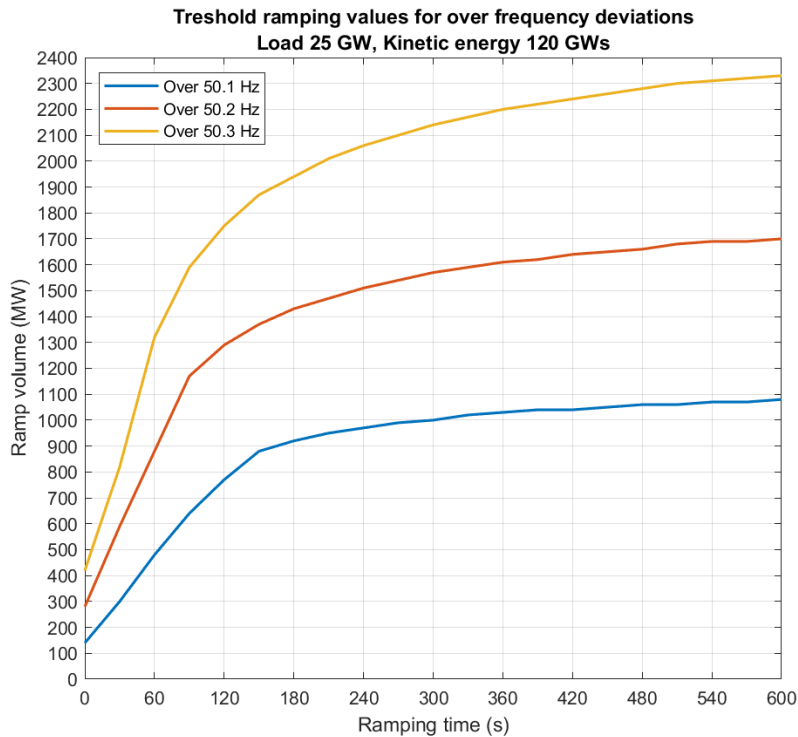


Figure 18: Threshold ramping values for over frequency deviations.

The results in Figures 17 and 18 were gained by simulating with low load and generation levels (25 GW) and with a very low level of kinetic energy (120 GWs). In practice, similar conditions can occur rarely in the summer when the power system demand is low, and the system is lacking the kinetic energy provided by the large synchronous generators. Simulating the frequency deviations in low load and kinetic energy situations gives the worst-case estimate of the impacts of the production ramping.

Figures 19 and 20 compare the low load/generation and kinetic energy conditions with moderate load/generation and kinetic energy conditions. The lighter colored curve was obtained with 25 GW of load/generation and 120 GWs of kinetic energy, and the darker colored curve was obtained with 40 GW of load/generation and 180 GWs of kinetic energy. The results show that higher load/generation and kinetic energy levels increase the volume of the production ramp that is needed for the frequency crossing. However, the effect is rather small particularly for smaller production ramps. Again, the results look very similar for over and underfrequency deviations.

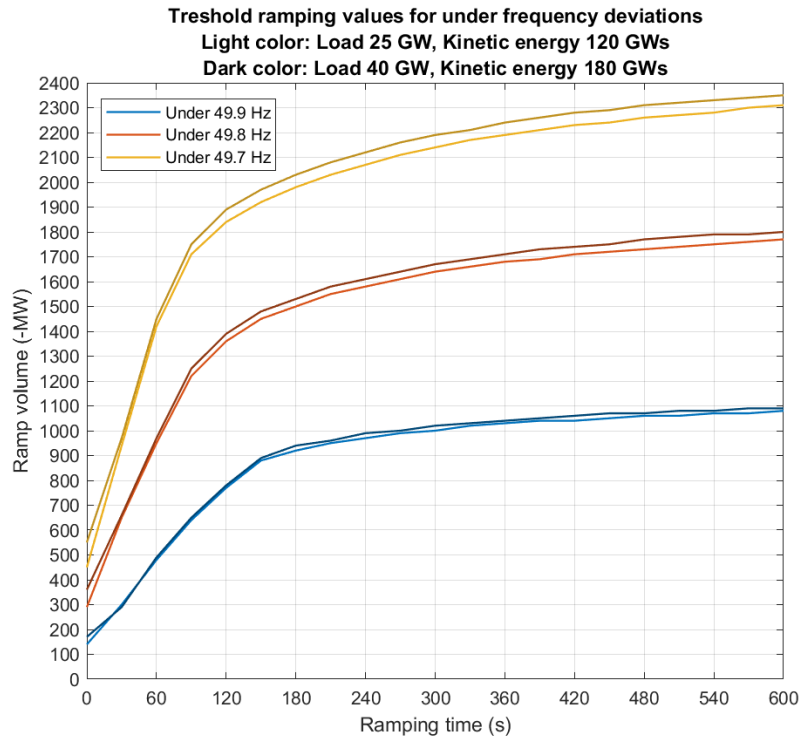


Figure 19: Threshold production ramping values for under frequency deviations in low and moderate load and kinetic energy situation.

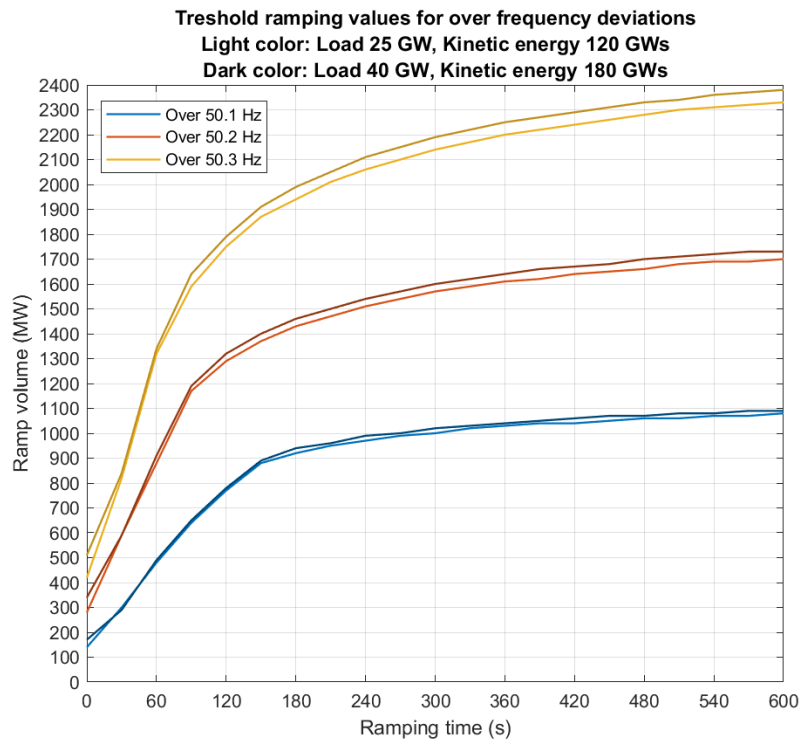


Figure 20: Threshold production ramping values for over frequency deviations in low and moderate load and kinetic energy situation.

The simulation results show that particularly the ramping time has a great effect on how much the frequency will deviate after a production ramp. With fast production ramps, increasing the ramping time significantly increases the ramp volume that is needed for the frequency crossing. However, with fast production ramps a relatively small change in the ramp volume can cause the frequency to deviate substantially more. With slow imbalance ramps the ramping time has less effect on the volume of the frequency deviation and the ramp volume needs to be large to cause the frequency to deviate substantially.

Running the simulation with different levels of load/generation and kinetic energy shows that the self-regulating effect of load is small, particularly for smaller imbalance ramps. Studying the inertial response of the model confirms that the effect of kinetic energy on the frequency deviations is most notable with fast production changes. The faster the ramping time is, the more the kinetic energy resists the frequency deviation. For large imbalance ramps the main increase in the ramp volume needed for the frequency deviation comes from the self-regulating effect of the load. This can be seen in Figures 17 and 18.

4.3 Model limitations

When interpreting the results of the simulation it is crucial to address the limitations of the model and the assumptions that were made in the simulation. Particularly for this simulation the results are directional and should not be interpreted as explicit. The purpose of the simulation is to give general understanding of the effects of production ramping rather than strict numbers.

One major assumption in the simulation is that the power system load does not change. In practice, this means that the production ramps are equal to the imbalance ramps. As discussed in Chapter 2.3, the deterministic imbalances at the MTU shift are essentially caused by the difference in the ramping speed of the rapidly ramping production and more gradually ramping consumption and HVDC transmission. It can be argued that including the demand ramping in the model could reduce the impact of the production ramping on the system frequency, especially when the production ramping is slow. However, including the consumption and HVDC ramping in the model would make interpreting and illustrating the model results more complicated. Without better knowledge of the ramping profiles of the consumption and the HVDC transmission, it is better to assume that the changes in the load and HVDC transmission are insignificantly slow compared to the changes in the production. This assumption holds up best with faster production ramps but is not reliable with slower production ramps.

Another shortcoming of the model comes from the model validation. The model used in the analysis was originally validated with real power system

disturbances. The model's simulated frequency response to disturbances was compared to the real power system's frequency response to disturbances. Disturbances are sudden events, but production ramping is a much slower phenomenon. The model was not validated for gradual production ramping which can affect the model results.

In practice, validating the model with real-life production ramps would be very challenging as it would require access to accurate measurement data of the production changes in the Nordic synchronous system. The production ramps used for the validation would have to be large enough to cause deterministic frequency deviation. It should be also ensured that the examined frequency deviations are, indeed, caused by the production ramping and not some other power system phenomena. Because of the difficulties related to the model validation, the approach in this simulation was to gain directive results.

As mentioned in the previous chapter, the reserve response of the model is outdated. Particularly the FCR response should be updated up to the current state and the FFR should be included for the simulations in low kinetic energy situations. Moreover, due to the limitations in the reserve response, the model does not perfectly account for the differences in over and underfrequency deviations. However, updating the model up to current specifications would most likely require a group of experts and is therefore out of question. Furthermore, the updates on the aFRR, mFRR and the new ACE model for balancing the Nordic synchronous system will change the very basics of Nordic balancing. Including these changes would require creating a completely new model from ground up.

5 Conclusion and discussion

The future need for the production ramping restrictions was evaluated in this thesis by analysing the production ramping in the Nordic synchronous system and simulating the effects of linear production ramping on the power system frequency.

Hydropower production ramping was identified as the single most important factor causing fast production changes and momentary imbalances at the hour shift despite the current production ramping restrictions. The 15-minute ISP and the quarterly day-ahead, intraday, and balancing markets will reduce both the net power system imbalances and the volume of the production changes and the structural imbalances at the hour shift. However, instead of one ramping period for the production at the hour shift, there will be four ramping periods between the quarterly MTUs. The volume of the production ramping at the MTU shifts ultimately depends on the changes in the demand over the course of the day and the hour.

The BRPs' willingness to address their quarterly imbalances in the intraday and day-ahead markets affects especially the volume of the hour shift production changes. If the quarterly imbalances are addressed by the BRPs in the intraday and day-ahead markets, the need for activating reserves is reduced. As a result, the final hour shift imbalances are also likely reduced.

Wind power production ramping caused by the negative day-ahead markets prices or 'price-induced wind power ramping' was identified as a special case of MTU shift production ramping that can possibly cause imbalances in the future power system. Based on the conducted analyses the thesis concludes that price-induced wind power ramping has occurred rather rarely in the recent years and is unlikely to have caused major frequency deviations. However, substantially more wind power production will be introduced in the Nordic synchronous system in the coming years.

The growth in the wind power production capacity will likely increase the market price volatility and the occurrences of negative day-ahead prices in the Nordic synchronous system. As a result, the conditions for price induced wind power ramping will become more favourable and the ramp volumes are likely to increase. However, the ramping decisions of individual wind power producers also depend on many other factors than the day-ahead price. Better understanding of the incentives for the price-induced wind power ramping could be a topic for future research.

The impact of linear production ramping on the Nordic power system frequency was simulated in Chapter 4. The simulation results indicate that especially the ramping time of the production has a significant impact on how much the frequency will deviate at the MTU shift. With fast ramping time the frequency can cross the threshold value even if the volume of the production ramp is relatively low. On the contrary, when the ramping time is slow the volume of the production ramp must be substantial for the frequency to cross

the threshold value. The level of kinetic energy has very little impact on the volume of the frequency deviation. The threshold curves for the production ramping obtained from the simulations give a rough estimate of how fast and large the production ramps need to be to cause a certain amount of frequency deviation. However, due to the limitations of the model the results should be interpreted as directive rather than explicit.

This thesis is cautious on totally abandoning the production ramping restrictions after the introduction of the 15-minute ISP and the quarterly day-ahead, intraday, and balancing energy markets. Although the quarterly balancing will reduce the volume of the production changes and the imbalances at the MTU shift, the speed of the production ramping is not affected by the change in the MTU resolution. If the BRPs continue to ramp quickly to the new set point at the MTU shift, momentary imbalances can occur at the MTU shift at least when the changes in the demand are substantial. There are also uncertainties related to the market participants' willingness to address the quarterly imbalances in the day-ahead and intraday markets. If the BRPs continue to trade mostly on hourly basis, the hour-shift production ramping will still be substantial, and it is more likely that the largest deterministic imbalances occur at the hour shift. Moreover, the rapidly increasing wind power capacity in the Nordic synchronous system can potentially increase the volume and the incidence of the price-induced wind power ramping.

Before transitioning to the quarterly day-ahead market, the ISP and the intraday market will move to 15-minute resolution. The majority of the electricity trade is still done on hourly basis in the hourly day-ahead market. As a result, the most significant changes in the production are likely to occur at the hour shift. However, the current ramping restrictions meant for restricting the hour shift production changes do not necessarily fit the transition phase with the 15-minute intraday market and the quarterly ISP. If the current ramping restrictions are still applied, the BRPs can in principle perfectly balance their quarterly imbalances in the intraday market and still be restricted by the 200 MW limit for the production change at the hour shift. Rescheduling the quarterly production plans around the hour shift would in this case result in reduced hour shift production change but possibly unsatisfactory quarter-hourly balancing.

The new production ramping restrictions should account for the production changes at the hour shift and the other MTU shifts. One possible solution to the problem could be to restrict the ramping speed of the production so that the imbalances are always netted over the quarter-hour. In up-ramping situation this would mean that the BRP would create deficit imbalance for the first half of the quarter and surplus imbalance for the second half of the quarter. This would in principle result to smooth production change instead of fast ramping at the MTU shift. However, the producers' ability to control their production in such manner should be researched and the financial impacts of limiting the ramping speed should be assessed.

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