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The need for Inertia in the Nordic Power System

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ABSTRACT

The Nordic power system is changing towards an increasing share of new renewable power sources. Conventional power sources contribute with a large amount of kinetic energy in the system due to their synchronously connected generators. This saves the system from large frequency deviations the first seconds after a power imbalance in the system. This kinetic energy is referred to as the system inertia. Wind power and HVDC do not have their kinetic energy connected directly to the system frequency like the conventional power sources. Nuclear and thermal power plants contribute with large reserves of kinetic energy. Hydropower contributes with a smaller amount of kinetic energy, but contributes with frequency containment reserves that are activated seconds after a disturbance. Both frequency containment reserves and system inertia are crucial to avoid large frequency deviations after a large power imbalance.

This thesis mainly focuses on the dynamic response after a disturbance. The system operators have several requirements for the frequency response and the power response after an outage occurs. The main part studied in this thesis is the maximum frequency deviation in the transient period, and the fastness of the system to provide extra energy.

This thesis studies the frequency stability in low load scenarios for the Nordic synchronous system, which includes Norway, Sweden, Finland and eastern Denmark. A model made in Simulink, which excludes voltage stability, rotor angle stability and load flow, investigates the balance between mechanical power and electrical load after a disturbance. It is assumed that the generation and the load are equal. The model was tuned based on a real response from an outage in the Nordic synchronous area.

The dimensioning incident in the Nordic power system today is 1400 MW. This means that the system should withstand a fault of this size, and still be able to operate within the requirements set for power response and frequency response. The simulations show that this can be challenging in several of the low-load scenarios.

There are two main scenarios, the first with conventional power sources. This is a scenario from an early morning in June 2013. The second scenario has large integration of wind power, HVDC and small-scale hydropower. Statnett has developed this worst-case scenario for 2020. Both scenarios have a total production of about 20 000 MW.

The first scenario shows that with a 50 percent share of hydropower, the system can only withstand an outage of 1300 MW maximum, with a large proportional gain in the hydropower governor.

The future scenario shows that synthetic inertia can make a large contribution to the system stability. With a well-tuned synthetic inertia contribution, the system will be able to withstand an outage of 1400 MW during low-load scenarios.

Some of the main findings are as follows:

A. Synthetic inertia is shown to have great effect on the frequency response in the transient period. It provides active power supply after a disturbance without contributing to reduce the frequency.
B. For a system at low load, the maximum frequency deviation is often at a critical point after a disturbance of the active power balance. This problem must therefore be addressed differently

than today. Today, the frequency containment reserves are purchased and it is assumed that the system inertia is sufficient. This is shown not to be the case.

C. To minimize the frequency deviation in the transient period, an active power supply like FCR and synthetic inertia is more efficient to apply to the system than a higher amount of system inertia.

SAMMENDRAG

Det nordiske kraftsystemet er i endring, med en økende andel nye fornybare energikilder. Konvensjonell kraftproduksjon fra vann-, kjerne- og termisk kraft bidrar med store mengder kinetisk energi til systemet i form av roterende masse som er synkront tilkoblet kraftnettet. I tilfelle en andel av produksjon faller bort, vil noe av denne kinetiske energien omgjøres til elektrisk energi. Dette vil bremse ned den roterende massen og igjen føre til et frekvensfall. Vindkraft og HVDC-kabler har ikke kinetisk energi synkront tilkoblet kraftsystemet.

Kjernekraft og termisk kraft bidrar altså med store mengder kinetisk energi. Vannkraft bidrar med noe mindre kinetisk energi, men bidrar igjen med store mengder primærreserver er viktig for å hindre store frekvensavvik ved feil i kraftsystemet. Både primærreservene og kinetisk energi tilknyttet systemet er viktig for å unngå for store frekvensavvik ved store forstyrrelser i effektbalansen mellom produsert og forbrukt elektrisk energi.

Studien tar i hovedsak for seg den dynamiske responsen etter en forstyrrelse. Systemoperatørene har flere krav til både frekvensresponsen og effektresponsen. Maksimalt frekvensavvik i den transiente perioden og hurtigheten på effektresponsen er de viktigste faktorene som blir studert.

Analysene er utført for det Nordiske kraftsystemet, som inkluderer Norge, Sverige, Finland og øst-Danmark. Simuleringene av systemet er gjort i Simulink med en modell som modellerer balansen mellom mekaniske og elektriske krefter etter en stor forstyrrelse i effektbalansen. Det er antatt at produksjon og last er det samme. Spenning- og vinkelstabilitet og lastflyt er sett bort fra ved modellerte av systemet. Modellen ble tilpasset etter en frekvensrespons fra det nordiske synkrone systemet.

Dimensjonerende feil i det nordiske kraftsystemet er 1400 MW. Dette betyr at systemet må kunne følge kravene som er gitt av systemoperatørene, selv om det oppstår en feil på denne størrelsen. Simuleringene viser at dette kan være utfordrende for flere av lavlast-scenariene.

Det er to hovedscenarioer. Ett med konvensjonelle kraftleverandører som er en faktisk driftssituasjon fra en tidlig morgen i juni 2013. Det andre scenarioet har en stor andel vindkraft, HVDC og småskala vannkraft. Det sistnevnte scenariet er utviklet av Statnett for å kartlegge hvordan systemets kinetiske energi blir ved lav produksjon med en stor andel kraftleverandører uten *inertia*-bidrag. Begge scenariene har en total produksjon på cirka 20 000 MW.

Det første scenariet viser at ved en vannkraftandel på 50 prosent kan systemet tåle et utfall på 1300 MW ved en høy forsterkning i vannkraftregulatoren.

Fremtidsscenariet viser at syntetisk *inertia* kan bidra mye til stabilitet i systemet. Med et godt tilpasset bidrag fra syntetisk *inertia,* kan system tåle et utfall på 1400 MW produksjon.

Noen av hovedkonklusjonene fra arbeidet er:

A. Syntetisk *inertia* har en positiv effekt på frekvensresponsen. Den bidrar med aktiv effekt uten å bidra til å redusere frekvensen.
B. Maksimalt frekvensavvik er ofte det kritiske problemet i lavlastscenarier etter en forstyrrelse i effektbalansen. Dette problemet må behandles med en annen metode enn i dag. I dag antas det tilstrekkelig kinetisk energi i systemet hvis det er kjøpt nok primærreserver, noe simuleringen viser at ikke alltid er tilfellet.

C. For å minimere frekvensavviket i den transiente perioden er det i flere tilfeller mer effektivt å tilføre systemet mer aktiv effekt, i form av FCR og syntetisk *inertia*, enn å sørge for mer naturlig kinetisk energi i systemet.

ACKNOWLEDGEMENTS

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1 INTRODUCTION

1.1 BACKGROUND AND MOTIVATION

The Nordic synchronous are has traditionally been a conventional power system with hydropower, nuclear power and thermal power as the largest providers of power. The production sources contribute with large amount of kinetic inertia to the system with their heavy synchronously connected machinery. If there suddenly is a loss of one power plant, up to 1400 MW electrical power production can disappear from the synchronous system. This leads to an imbalance between production and load, and the heavy synchronously connected generators can deliver more electric energy than received mechanical energy for a short time, by transforming the kinetic energy to electric energy. This will slow the machines down, and the frequency will drop. After a few seconds, the frequency containment reserves will activate, the machines will speed up and the frequency will recover. This effect from the kinetic energy that is called the *system inertia* is crucial to stop the frequency to drop too low during unplanned imbalances. Hydropower is the main supplier of frequency containment reserves.

However, the power system is changing and will continue to change in the nearest future. Nuclear power contributes with the largest amount of kinetic energy. For the first time on May 31th, 2015 and June 1^{st,} 2015 wind power was producing more energy in Sweden than nuclear power [1]. Hydropower contributes with the important frequency containment reserves and kinetic energy. Due to mechanisms in the power market, it is economically beneficial to stop the hydropower during the night hours and import energy through HVDC-cables. This effect will be stronger in the future due to a closer connection to countries in Europe like Denmark, Germany and the UK with several HVDC cables [2] towards 2020. The transfer capacity between Norway and Europe (including Denmark) will rise from 1700 MW in 2013 to 5200 MW in 2020. The total capacity for the Nordic power system in total will increase with 5000-6000 MW to around 11000 MW. This will influence the operating conditions and it is questioned how this will affect the frequency stability. Wind power, solar power and HVDC cables do not contribute to system inertia. Figure 1 shows the development of the system inertia in the grid in the UK have been reduced the last years.

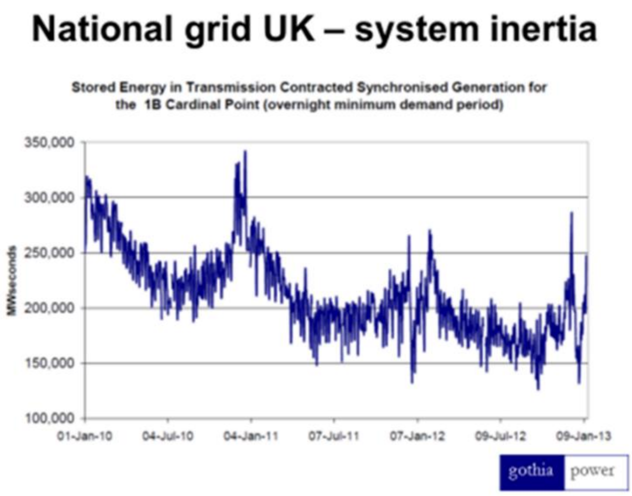

Figure 1: The amount of kinetic energy in MWs in the synchronous system in UK [3].

The question is, how can the system operate within safe limits with these new challenges.

1.2 SCOPE OF WORK

This thesis will look into how the system frequency response is and will be at low load. Low load entails low kinetic energy, so two scenarios will be looked into in particular. Several factors have an effect on the frequency response after a disturbance. These factors are investigated to improve the frequency response.

Several test for different varieties of the scenarios are tested. It is seen how large amounts of production each variety can withstand, if the requirements for the frequency response set by the system operators shall be adhered.

Today, the frequency containment reserves are purchased in the power market, and it is assumed that the system have enough inertia when there are enough frequency containment reserves. This assumption is tested. The question is, is this assumption valid or should there be a new system that ensures enough system inertia.

The thesis also investigates new technology that can provide synthetic inertia from HVDC and wind power and how large contribution this technology can offer.

1.3 SYSTEM DESCRIPTION

The Nordic synchronous area (NSA) is the system that has been studied. The grid in Norway, Sweden, Finland and eastern-Denmark forms the NSA [4] like Figure 2 shows.

Figure 2: The Nordic synchronous system

The balance between mechanical and electrical power with contribution from inertia and simple control mechanisms are modelled in Simulink, MatLab. The principal model is shown in Figure 3. The total production divided into the different power sources and the assumed system inertia in the Nordic synchronous area have been inputs to the model. The model was tuned after an actual response.

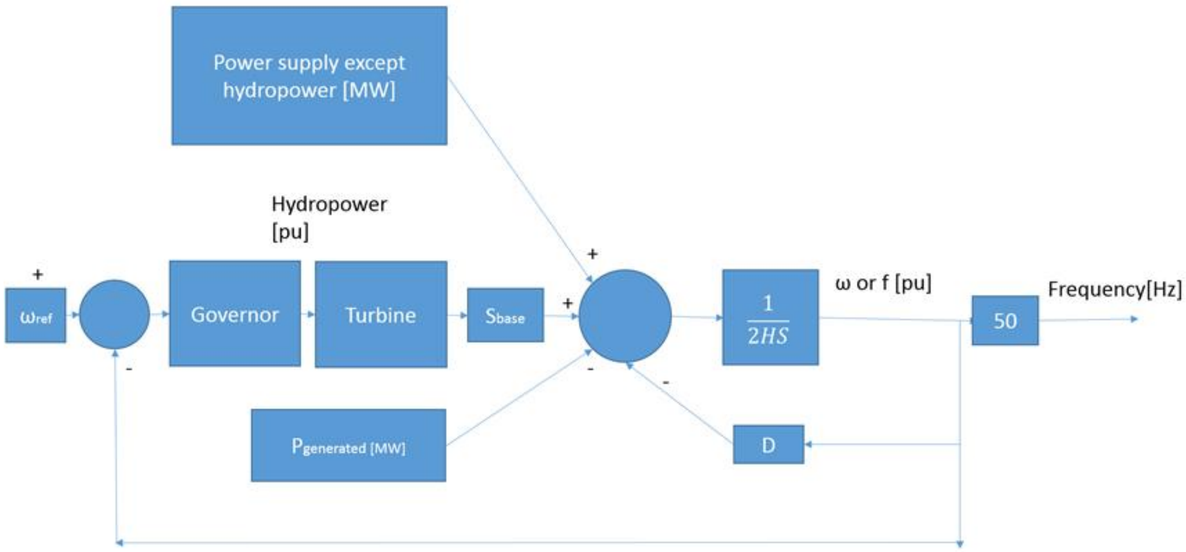

Figure 3: The principal model of the system studied in the thesis.

1.4 Outline of thesis

The thesis starts with an introduction to the concept used to solve the problems. Simple concepts, introduction to inertia, both natural and synthetic, and presentations of the different steps regarding frequency behaviour after a disturbance have occurred in the system. In chapter three and four, the method for the task and the model is presented. This includes the limitations for the study and how and which factors that are considered during the simulations. Chapter five presents the result from the simulations for all the scenarios. This chapter starts with tuning the model to a real response from March 5th, 2015 when there was a large disturbance in the system. Followed are two low load scenarios, one with conventional power sources and one scenario that have a large share of wind power, small-scale hydropower and HVDC. The thesis ends with the *discussions*, *conclusion* and *further work.*

2 INERTIA AND FREQUENCY CONTROL IN THE POWER GRID

2.1 DEFINITION OF CONCEPTS

2.1.1 Power system stability

To stabilize an electric power system it is necessary to balance generated and consumed real power together with losses. With an imbalance between these factors, the frequency in the power system will fall or rise instantaneously [5]. When there is a loss of power or load, it is called a disturbance or a fault. Power system stability is the ability the system has to regain steady state operation after a disturbance [6].

2.1.2 Spinning reserve

Spinning reserve is the difference between power rating of a generator and the actual load [6]. It is important to allocate spinning reserves in a power system, because it influence its generation characteristic. If a system at any operating point has little or no spinning reserves, an outage can lead to a frequency break down. The generators thermal and mechanical limits set a maximum production level. Only the connected generators provide spinning reserves.

Reserve power from wind turbines

Normally, variable speed wind turbines do not contribute with spinning reserves or spare capacity [7]. The design of WTGs (wind turbine generators) makes the wind turbines to operate at maximum power point tracking (MPPT). However, by actively using the pitch control of the turbines, WTGs can contribute with extra capacity for unbalanced situations. This practise does not utilize the wind fully and is not a good way to provide extra energy. This technology is normally only considered for very special operating conditions.

2.1.3 Transient response

The transient response is the response that the system has after a sudden disturbance [8]. The system is transient stable if it has the ability to keep the generators in synchronism and reach steady state operating conditions after a fault. Transient stability is normally mentioned when voltage stability is revised. In this thesis the transient response is used to describe the period before the frequency reaches a new steady-state level.

2.1.4 Droop

The droop can be defined as the change in frequency divided by the change inn load. Figure 4 defines the equation for the droop *R.* The characteristic shown in Figure 4 is valid for one generator. Adding the Load-frequency-characteristics for all the generators gives the generation characteristic for the system. This characteristic defines how the system will respond to an imbalance in the system. For a large power system, the characteristic will be almost horizontal [6]. This is an important argument to make large power system, since it will make the system more suited to handle a large power change with a very small change in frequency.

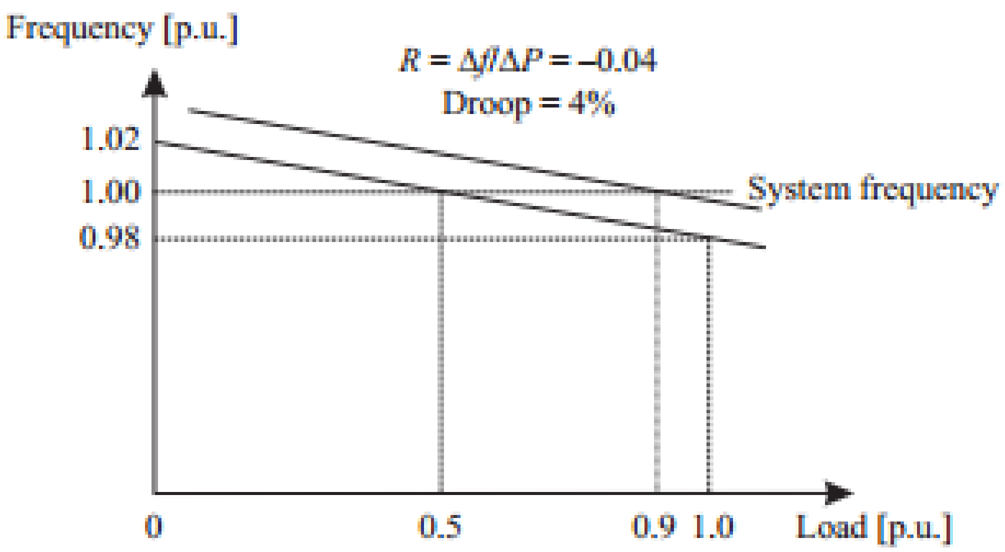

Figure 4: Governor droop operation with 90 % load and 100 % frequency [8].

Equation 1 and Equation 2 describe the frequency change in relation with the loss or increase of power. ρ_t is the local speed droop and is the inverse of *R*. The speed droop is a defined by where the spinning reserves are located in the system and the quantity of spinning reserves. The coefficient K is the frequency sensitivity of the power system.

Equation 1

$$\frac{\Delta f}{f_n} = -\rho_i \frac{\Delta P_{mi}}{P_{ni}}$$

Equation 2

$$\frac{\Delta P_{mi}}{P_{ni}} = -K_i \frac{\Delta f}{f_n}$$

The droop can be affected in several ways. This tells how the frequency reserves activate in case of a disturbance or a load change. There are several ways to affect the frequency reserves by changing the droop. By keeping stations running at low load and at a decreased droop setting leads to an increase for the frequency containment reserves and the frequency restoration reserves. The droop setting can be used wisely to improve system stability [9].

The frequency bias factor is given in Equation 3. This tells how much the system reacts to a change in frequency if a certain amount of power is lost, or how much power that must be forced upon the system in order to lift the frequency Δf Hz [6].

Equation 3

$$\Delta P = \lambda_R * \Delta f$$

2.1.5 Frequency response

Frequency response is the ability of the system to react automatically at an active power imbalance [10]. Figure 5 shows a typical frequency response after an imbalance in the system.

The frequency response is typically divided in three categories. These include inertial frequency response, primary frequency response and secondary frequency response. The inertial frequency response is the time when the frequency depends on the stored kinetic energy in the rotating masses. This response reacts to an active power imbalance within seconds. In Figure 5, the inertial frequency response is between point A and C. After 12 to 14 seconds, the governors will increase or decrease the power output according to the frequency deviation. This is the primary frequency response and is the response seen between C and B in Figure 5. Finally, the AGC[1] executes the secondary frequency response. This can take from 30 seconds to several minutes and will adjust the system back to a frequency to normal operation. The secondary frequency response is not shown in Figure 5.

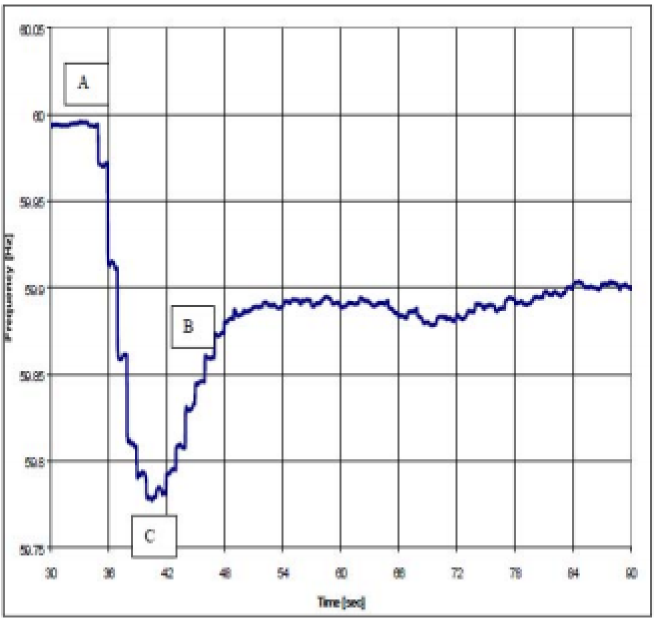

Figure 5: A normal frequency response after a disturbance.

2.1.6 N-1 criteria and dimensioning incident

The N-1 criteria expresses that the system shall function and operate within satisfactory limits with the loss of one component of any kind. This includes all kinds of power system component like production units, lines, transformers, bus bars etc. The system must be prepared and able to lose the component that will influence the power system stability the most. Dimensioning incident is the largest incident the system must be prepared to withstand at any time. This is normally the largest power station and is important to determine necessary amount of FCR (frequency containment reserves) and FRR (frequency restoration reserves) Dimensioning incident in the Nordic synchronous area is currently 1400 MW, but is increasing to 1650 MW when a new nuclear power station is connected in Finland [11-13].

[1] AGC - Automatic generation control

2.2 FREQUENCY CONTROL AND POWER SYSTEM STABILITY

Power system stability is divided into three categories in [6]: Rotor angle stability, frequency stability, and voltage stability. This thesis will look into frequency stability.

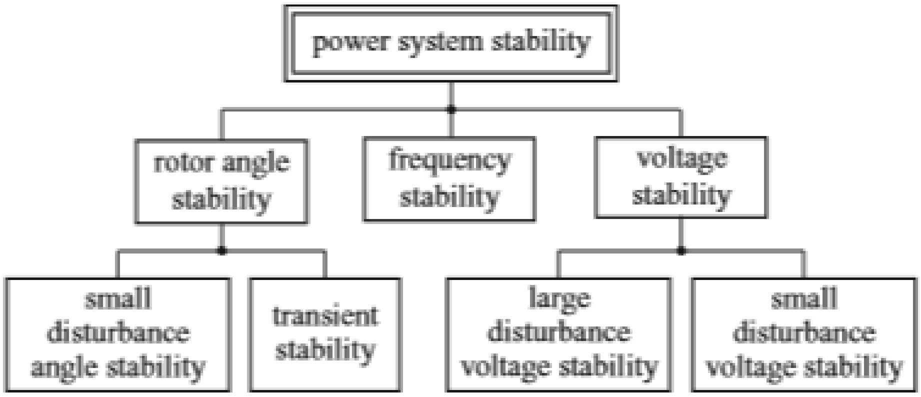

Figure 6: The overview of the categories in power system stability

The frequency in the Nordic system must satisfy the quality criteria that the TSO's in the Nordic countries have agreed on. For normal operation, the aim is to maintain the frequency within the normal range of 49,9- 51,1 Hz. The requirement for frequency containment after a disturbance is that the stable frequency should be no lower than 49,5 Hz. To meet these requirements there must be constant control of frequency [4].

When there is active power imbalance in the system the power system responds in five stages [6]. The stages in which the power system responds are as follows:

I. Rotor Swings in the generators (first few seconds)
II. Frequency drop (a few to several seconds)
III. Primary control (several seconds)
IV. Secondary control (several seconds to a minute)
V. Tertiary control

The first three parts where presented in 2.1.5.

2.2.1 Rotor swings in the generators

If there is a disturbance in the active power balance, there will be change in speed for the first few seconds after the disturbance. If there is an outage of one generator unit, other generators in the system must compensate for the loss of active power. The electric energy delivered to the grid from the generator is greater than the received mechanical energy during this period. This slows down the rotating masses of the generator. The time it takes to convert the kinetic energy from the rotating masses is the inertia time constant. If there is loss of load, the rotating masses will store the excess energy and therefor accelerate their rotors [6].

2.2.2 Frequency change

After a few seconds, the system will restore the balance between generation and demand. The generators of the system will increase or decrease their speed, and the frequency will drop or rise. If the frequency drops, each generator of the system will contribute to stabilize the frequency by delivering more active power. The inertia constants of the generators decide how large the power contribution will be before the governors provide extra energy. The extra energy is mechanical energy from water, steam, etc. The concept of inertia is presented below.

2.2.3 Primary control and FCR

FCR (frequency containment reserves) are active power reserves that activates automatically as a response to a change in system frequency. The Nordic system distinguishes between FCR for normal operation and for disturbances. This is respectively FCR-N and FCR-D. These reserves activate automatically [14].

The FCR activates within a few seconds when there is an active power imbalance in the system [6]. If there is an outage, the governors[2] will increase the production of active power to limit the change in the frequency. For this to happen there must be available spinning reserves in the system. This will stabilize the system at a lower frequency level than before the outage.

The activation of the frequency containment reserves (FCR) is as also termed primary control. Today the requirement for FCR-N in the Nordic synchronous system is 600 MW available within 0,1 Hz. Of this, 210 MW is located in Norway [9]. The frequency bias must therefore be 6000 MW/Hz in the system.

There are some imbalances in the beginning of the primary control. The governors will continue increasing the mechanical power after reaching the equilibrium point. This happens because the inertia will add time delay to the turbine regulation process. This leads to some temporary imbalances between load and generation. Figure 7 illustrates this concept of temporary imbalance. P_T is the turbine power that suddenly drops, and P_L is the power for the load.

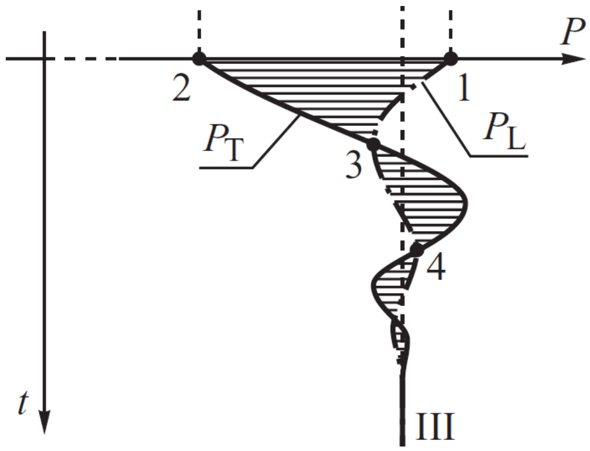

Figure 7: The imbalances between load and generation after the activation of the governor control [6].

Equation 4 determines the frequency deviation [6]. Δf_p is the deviation between the nominal frequency and the stable frequency level in the primary control period. Both *p* and *r* are coefficients that relates to available spinning reserves, and both are zero when there are no spinning reserves in the system. The coefficient *p* is the power rating of the generator units that operate in the linear part of their characteristics divided by the total power rating of the system. The coefficient *r* is the available spinning reserves divided by the load. *K* is the frequency sensitivity and K_L is the frequency sensitivity of the demand. ΔP_0 is the power change. This is a more detailed equation of what the droop equation showed.

[2] A governor controls the speed or the output power according to the power-frequency characteristics.

Equation 9 shows how important the spinning reserves of the system are to frequency sensitivity. The coefficient *r* and *p* are always between zero and one, and they decrease proportional with the spinning reserves. A small amount of spinning reserves in the system will therefore cause a large frequency deviation compared to the same outage but with a larger amount of spinning reserves.

Equation 4

$$\frac{\Delta f_p}{f_n} = \frac{-1}{p(r+1) * K + K_L} * \frac{\Delta P_0}{P_L}$$

The secondary and tertiary control will eliminate the frequency deviation.

2.2.4 Secondary control and FRR

The secondary control response is required within the period from 30 seconds to 15 minutes. This is the requirement for the system. Many of the generators will have a faster response, but the system operators require that the frequency restoration reserves (FRR) to start activating within 30 seconds and be fully activated within 15 minute. This is performed by automatic generation control or manually. The purpose is to get the frequency within the normal operating limits to restore the primary reserves and be prepared to withstand another possible disturbance.

The secondary control should return the frequency back to nominal value. It is done by changing the set point in the power-frequency characteristics. By changing the reference value for the active power in the governing system, the characteristic will change. The governors will increase or reduce the output of the generator. There are still discussion for how large reserves that should be required for the FRR [6, 8].

2.2.5 Tertiary control

Different power systems need different tertiary control systems due to their different structures. Tertiary control releases the FRR and the spinning reserves to make the system prepared for a new disturbance. Norway has a demand for replacement reserves (RR) for 1200 MW for tertiary control. The tertiary control optimizes the new operating point, regarding optimal power flow and economic dispatch. In worst case, tertiary control can involve load shedding. These loads losing their power supply normally have agreements regarding situations like this [4, 6].

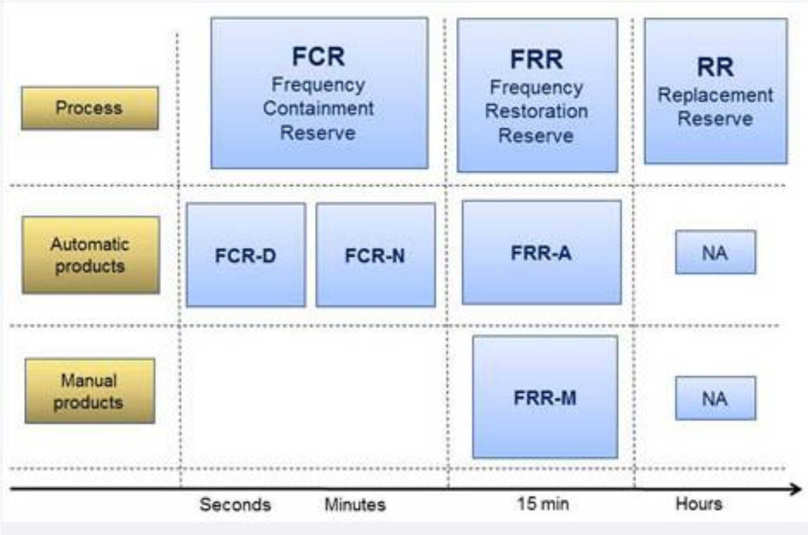

Figure 8: The system structure for activating reserves after a disturbance [4].

2.2.1 Load shedding and frequency collapse.

Load shedding normally starts when the frequency drops to 48-48,5 Hz, but if the frequency drops below 49.0 Hz, some initial load shedding can occur in the Nordic system, in particular on the HVDC connections [7, 15].

Load shedding is the last resort to avoid a total frequency collapse, which can happen if the load demands are not met by the generation. The power-frequency characteristic will operate outside their safe area, and there can be a frequency collapse. Load shedding is performed with under-frequency relays and can shed large areas. The relays are depending on the frequency, which means there is a time delay from the actual disturbance before the frequency reaches a level where loads are decoupled. With less system inertia in the future, this is expected to be a problem. A revision of the protection schemes must be considered due to this effect *[6, 7].*

2.2.2 System operation agreement

The transmission system operators (TSOs) have set requirements and agreed on operational strategies and limits for the frequency response in case of a disturbance.

A system operation agreement (SOA) is established between the operators of the power system in Norway, Denmark, Sweden and Finland. The grid in eastern Denmark and the grid in the three other countries are synchronously interconnected and the quality of the power supply in all the countries will suffer from disturbances in one of the systems. Therefore, all the parties are responsible to uphold the necessary quality and reliability in the power system [12].

The requirements to frequency quality in this agreement are as follows:

1. If the frequency deviates from 50 Hz within the frequency band 49,9-51,1 Hz, it should be regulated back within 2-3 minutes. The FCR-N should be at least 600 MW and fully activated within 0,1 Hz deviation from 50,0 Hz. How much FCR-N each country must provide is as presented in Table 1.
2. If the frequency drops below 49,9 Hz the FCR-D should be activated. At 49,5 Hz the FCR-D should be fully activated. The dimensioning fault cannot cause a frequency below 49,0 Hz. The requirements for each TSO are presented in Table 1.

3. FCR-D response has a requirement regarding the response time. Within five seconds after a disturbance, 50 percent of the reserves should be activated. After 30 seconds, 100 percent should be activated.
4. FRR should be fully activated within 15 minutes.

Table 1: How much FCR-N each country must provide for FCR-N and FCR-D.

Frequency containment reserves		
	FCR-N [MW]	FCR-D [MW]
Eastern Denmark	22	176,5
Finland	138	258,8
Norway	210	352,9
Sweden	230	411,8
Total	**600**	1200

2.3 INERTIA AND KINETIC ENERGY IN THE SYSTEM

2.3.1 Inertia

The rotating masses in the system can prevent large frequency deviations after a disturbance by using their stored electric energy also called the inertia. When there is imbalance between load and generation, a frequency change will occur because the rotating masses will change their speed. The frequency will change because the machines that control the frequency are synchronous machines and are directly connected to the system frequency with their rotating parts. If the mechanical power is larger than the electrical load, the rotating masses will store the excess energy by accelerating the rotating part. This will increase the system frequency. If the load is too large compared to the mechanical power, the rotating masses will provide the lacking energy by using its stored kinetic energy by decelerating. This will decrease the frequency in the system [6, 8].

The Inertia constant H of a power system describes the initial, transient, frequency behaviour of the system during a large change in real power [5]. The inertia is one of the main factors to consider when frequency stability is calculated for a system [16].

The inertia constant H is given in seconds or in MW-s/MVA [8]. The system inertia constant tells us how many second it will take to provide electric energy equivalent to the stored kinetic energy in the rotating masses in the system [6]. The system inertia can be calculated when a large generator or a power plant trip from the response of the system. The value of the system inertia will vary with the amount of spinning reserves, the load and the generation. Equation 5 defines H as the inertia constant.

Equation 5

$$H = \frac{Stored\ kinetic\ energy\ at\ synchronous\ speed\ [MW - s]}{Generator\ MVA\ rating[MVA]} = \frac{J * \omega_s^2}{2 * S_{rated}}$$

2.3.1 Swing Equation

The system inertia is important in the *swing equation* for a system. The swing equation defines the relationship between electrical and mechanical power of a machine, the frequency change and the inertia of the machine[5]. Newton's second law is the basis for the swing equation. Equation 6 presents Newton's second law in the form that is used to derive the swing equation [6].

Equation 6: Newton's second law. J is the total moment of inertia, ω_m is the speed of the rotor shaft, D_d is the damping torque and τ_t and τ_e is respectively the turbine torque and electrical torque.

$$J * \frac{d\omega_m}{dt} + D_d\omega_m = \tau_t - \tau_e$$

Equation 6 shows that any imbalance between the electrical and mechanical torque will accelerate or decelerate the rotor. The model includes the damping power of the system. The damping power is the frequency dependent part of the load.

Equation 7 is a common form of the swing equation. $\Delta\omega$ is the derivative of the rotor angle and the angular position of the rotor speed referred to the synchronous speed.

Equation 7: H is the inertia, S_n is the rated power of the machine, ω_s is the synchronous speed, Δω is the rotor speed deviation and P_m, P_e, P_D and P_{acc} is respectively the mechanical, electrical, damping and accelerating power.

$$\frac{2 * H * S_n}{\omega_s} * \frac{d\omega}{dt} = P_m - P_e - P_D = P_{acc}$$

The swing equation is valid for the system at all time and very useful after an imbalance of real power occurs [5]. This connects the change in frequency directly to the power imbalance. The swing equation can calculate the system inertia as well as the inertia for a specific generator.

For the multi machine system, by summing up each side of the equation, the total inertia constant is found for the system.

$$2 * H_1 * S_1 * \frac{d}{dt}\omega_1 = P_{M,1} - P_{L,1}$$

$$2 * H_2 * S_2 * \frac{d}{dt}\omega_2 = P_{M,2} - P_{L,2}$$

$$\omega_1 = \omega_2 = \dots = \omega_n = \omega_{sys}$$

$$(2 * H_1 * S_1 + 2 * H_2 * S_2 + \cdots + 2 * H_n * S_n) * \frac{d}{dt}\omega_{sys} = P_{M,tot} - P_{L,tot}$$

The system inertia is defines as below

$$H_{sys} = \sum_{i=1}^{n} H_i S_i$$

This gives the equation:

$$2 * H_{sys} * \frac{d}{dt}\omega_{sys} = P_{M,tot} - P_{L,tot}$$

In Figure 9, the balance between the mechanical energy from the turbines and the consumed power is visualized. This model implies that there is an assumption that the load and the generated power is the same. The imbalance is between mechanical and electrical power, not generated electric power and consumed electric power. Losses are ignored. When there is an imbalance between the mechanical powers and the consumed electrical power, the mechanical part must deliver an increased amount of electric energy to provide the constant load.

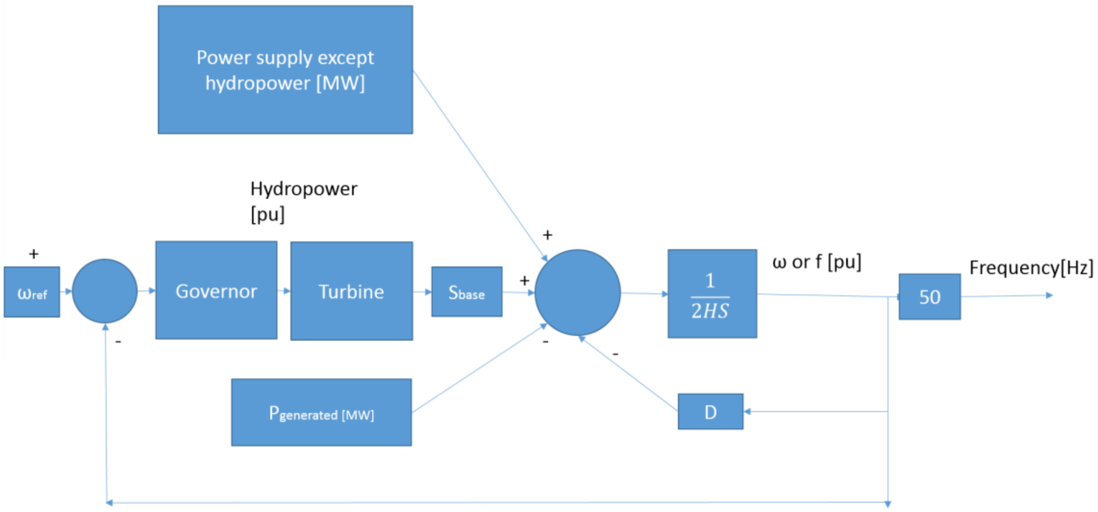

Figure 9: Block diagram of system frequency response, inertia, droop, and damping.

Inertia constants for different types of machines

The inertia contribution from different generators varies. Table 2 Table 2 and Table 3 show examples of values the inertia constant may have. The reasons that cause the inertia constant to vary are the design, the weight and the speed. Inertia constant for hydropower is low despite their heavy constructions because the generators rotate relatively slowly compared to the generators for thermal and nuclear. The electrical speed is the same, but the actual speed is much lower for hydropower.

The system inertia constant is normally in the rage of 2 – 10 seconds [8].

Table 2: Shows different inertia constants for different machines and production types.

Type of Machine		*Intertia Constant H Stored Energy in MW Sec per MVA***
Turbine Generator		
Condensing	1,800 rpm	9-6
	3,000 rpm	7-4
Non-Condensing	3,000 rpm	4-3
Water wheel Generator		
Slow-speed (< 200 rpm)		2-3
High-speed (> 200 rpm)		2-4
Synchronous Condenser***		
Large		1.25
Small		1.00
Synchronous Motor with load varying from 1.0 to 5.0 and higher for heavy flywheels		2.00

Statnett uses the constants presented in Table 3 to calculate the inertia.

Table 3: Inertia constants used by Statnett.

Inertia constants from Statnett	
Production source	**H [s]**
Nuclear	6,3
Thermal	4
Conventional hydro	3
Small Hydro	1

Figure 10 shows the level of system inertia in the NSA in a period in 2014. With respect to the inertia constants for the different power sources, the concern is that this total amount of system inertia will decrease with an increase of power sources that do not provide system inertia like wind power and power transfers form HVDC-cables [17].

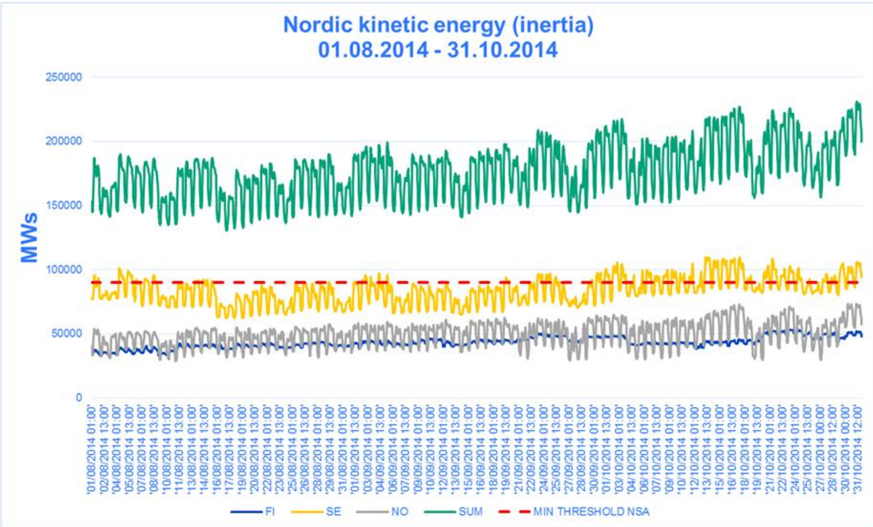

Figure 10: The total system inertia in the Nordic synchronous system in a period in 2014 [17].

2.3.2 The relation of inertia, droop and transient response

The effect that different inertia values have on the frequency response is graphically shown in Figure 11.

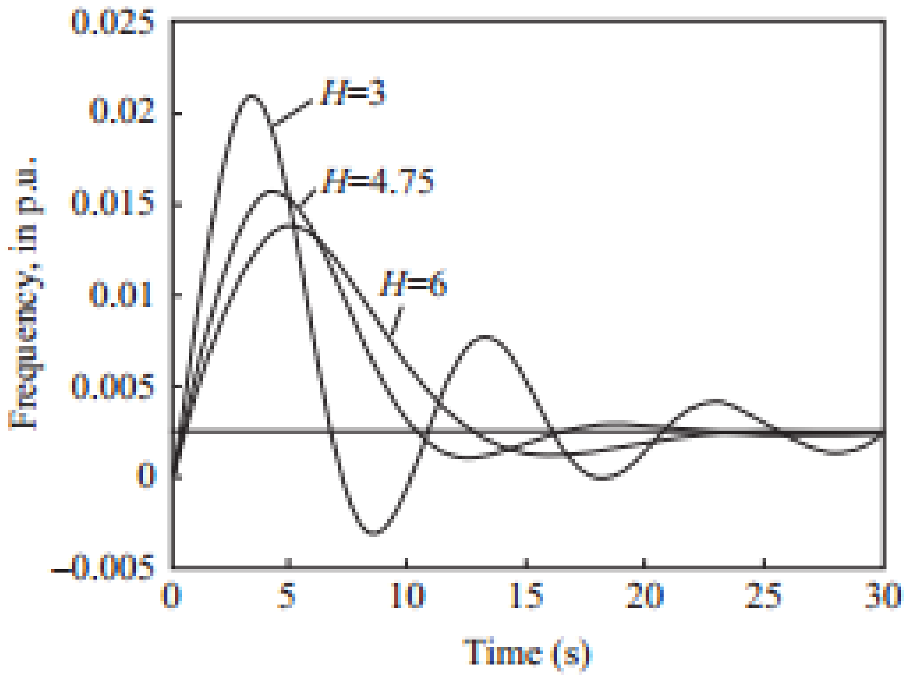

Figure 11: The effect of different inertia constants with a 5 % load step change [8].

Different inertia constants will influence the transient response after a change in the balance between supply and consumption of active power [8]. High inertia contributes in making the transient response less steep and more damped.

In real values, the imbalance will influence the system like shown in Figure 12.

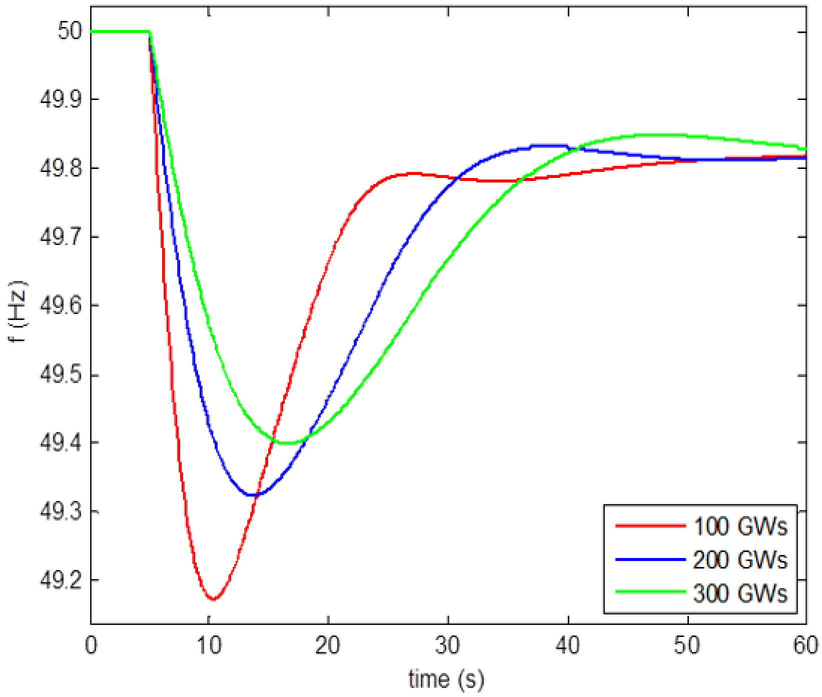

Figure 12: In real values, a frequency disturbance can look like this. The different graphs are for different values of H – the inertia constant. (Statnett)

2.3.3 Synthetic inertia

Synthetic inertia is a controller that creates inertial response from wind power, HVDC or solar power [7, 18]. Wind turbines are isolated from the system frequency by AC/DC/AC converters and will not naturally respond to change in system frequency. A predetermined operating characteristic controls the power output by the main control loop in the generator in the wind machine. The control loop measures the speed of the rotor and adds a suitable torque to the rotor. The control loop will make the wind turbine always operate at maximum power point tracking (MPPT) and therefore they have no spare power to contribute with during low frequency events [19].

However, modern wind turbine generators (WTG) can be equipped with synthetic inertia and provide inertia during large, short-term frequency disturbances. In some extension, these controllers can provide governor control as well. Figure 13 and Figure 14 shows examples of control loops that can be added to a generator. These control loops will register the frequency deviations and add a higher torque to the turbine. The turbine will at this point deliver a larger amount of power than the MPPT rating. This will slow the turbine down, and deliver extra electric power during a low frequency event. The idea of synthetic inertia is to release the kinetic energy that is not synchronously connected to the systems frequency. Synthetic inertia from wind power is asymmetric, which means it can only slow down and deliver extra energy during disturbances that decreases the frequency. During high frequency events, the wind turbine will not speed up [7, 19, 20].

This model shown in Figure 13 can only release inertia for a period of less than 30 seconds. Afterward, the wind turbines will withdraw electric power from the grid to restore its original speed.

For large under frequency events the controllers can deliver five to 10 percent more energy than the WTGs rated values. It is worth noticing that synthetic inertia from wind turbines do not contribute to the frequency restoration phase. When the derivative of the frequency is positive, the wind power that has provided synthetic inertia starts to absorb extra power from the grid to speed up their wind turbines. This is called the recovery energy.

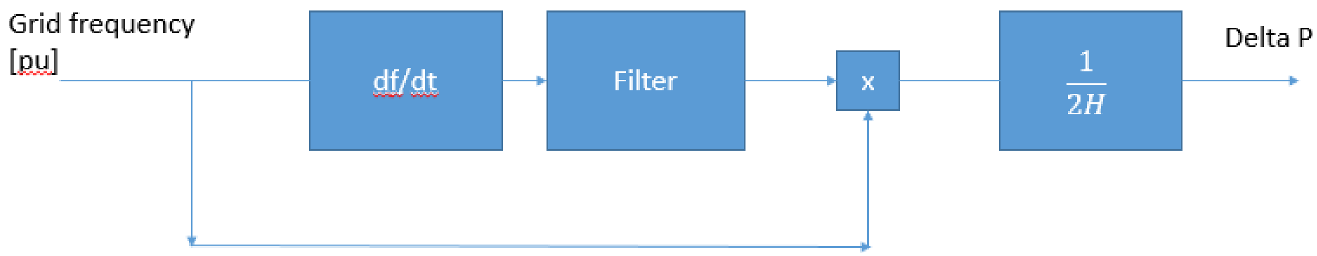

Figure 13: A block diagram of a controller that provides synthetic inertia.

Equation 8 is the equation used to generate the plot in Figure 13. H_{syn} is the inertia constant for the synthetic inertia and ΔP is the delivered energy from the wind farm.

Equation 8

$$\Delta P = 2 * H_{syn} * f_{sys} * \frac{\Delta f_{sys}}{\Delta t}$$

In Figure 14, the control loop that GE use when installing their wind turbines is shown. This model differs from the previous shown model, but was recommended by Professor Kjetil Uhlen [21, 22].

This model shows that the derivative of the frequency is the only factor that controls the power output from the synthetic inertia. The model gains the signal of the derivative of the frequency. The input for the gain block is [Hz/s], and the K_{WI} therefore has the unit [MWs/Hz]. The derivation happens in the wash-out filter.

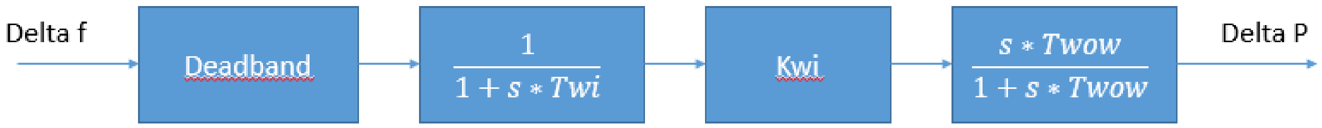

Figure 14: Control model for wind inertia [20].

Figure 15 shows a typical response for a wind turbine together with the response for the system speed or frequency[3]. This method has used both the frequency and the derivative of the frequency. This graph shows that after the wind turbine have delivered more energy than received, it delivers less than received. This is the recovery energy. In this model, the recovery energy is simply a lower power output than the initial value before the disturbance. In this period, the wind turbine will receive more energy than delivered, and the speed will recover.

[3] The systems frequency and speed has the same value in per unit.

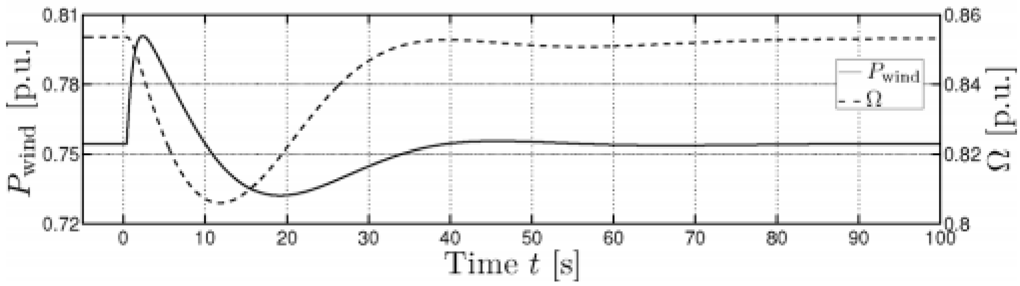

Figure 15: A typical response from synthetic inertia. The solid line (P_{Wind}) is the response from the wind power and the dotted line (Ω) is the synchronous speed in for the systems synchronous machines [23]. This method uses both the frequency and the derivative of the frequency.

2.3.4 HVDC, synthetic inertia, and emergency power.

Synthetic inertia

There are two main ways of HVDC-cables of delivering inertia to the system that will be presented. The first one focus on line-commutated converter (LCC)-based HVDC that have a large transfer capability. The second focuses on voltage source converter (VSC)-HVDC systems [24].

LCC-BASED HVDC

LCC-based HVDC or traditional HVDC can deliver inertia to a synchronous system. To deliver synthetic inertia from traditional HVDC cables, a droop coefficient must be added to the power output equation together with a derivative of the system frequency [24]. To make a HVDC cable provide inertia a frequency droop is added to the HVDC rectifier control. Figure 16 shows a principal block diagram of the rectifier. The point is that the *K* or *1/R* should function the same way as the droop in the governor of a synchronous machine. P_{ord} is the ordinary output data for the HVDC cable. This equation reminds very much about a very fast response as frequency containment reserves. The only part that makes this synthetic inertia is that the factor that provide it is the derivative of the frequency.

Equation 9

$$P_{DC} = P_{ord} - K\frac{df}{dt}$$

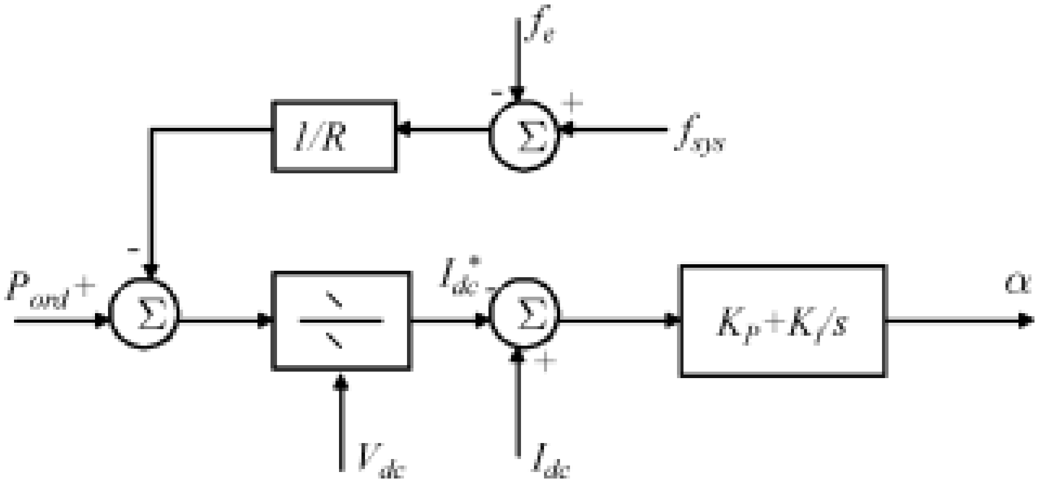

Figure 16: The rectifier for a HVDC-cable that provides inertia.

This data is originally presented for an HVDC connected windfarm, but it is assumed that the concept will be similar.

VSC-BASED HVDC

Light HVDC links or VSC-based HVDC can also deliver synthetic inertia by realizing the stored kinetic energy within the HVDC DC capacitors [25]. This is called inertia emulation control, and is developed to work for HVDC cables with voltage source converters. The mechanism also contributes to FCR. The converters that control the voltage also control the inertia contribution and it is claimed that many inertia-time constants can be emulated by this Inertia emulation control. This is still unproven technology and no tests are presented in [25].

ABB presents that they have successfully implemented inertia support in an HVDC link between Namibia and Zambia [26]. ABB explains that *the converters have a characteristic comparable to an infinite AC source or a slack bus*. Figure 17 shows the response in the areas. The three graphs to the left in the model are for Namibia and the grid that had a disturbance. The power in the lower graph shows an export that is almost immediately reduces the power to zero when the disturbance happened. The left part shows the graphs for Zambia and the grid that suddenly lost 80 MW imported power. Almost immediately after the disturbance, the power flow ends. This is shown in the bottom graph.

The fault was a bus tripping and the disturbance was large as the frequency for the grid in Namibia shows. The cut in import did not affect the frequency in the receiving grid especially. The initial import for Zambia was 80 MW.

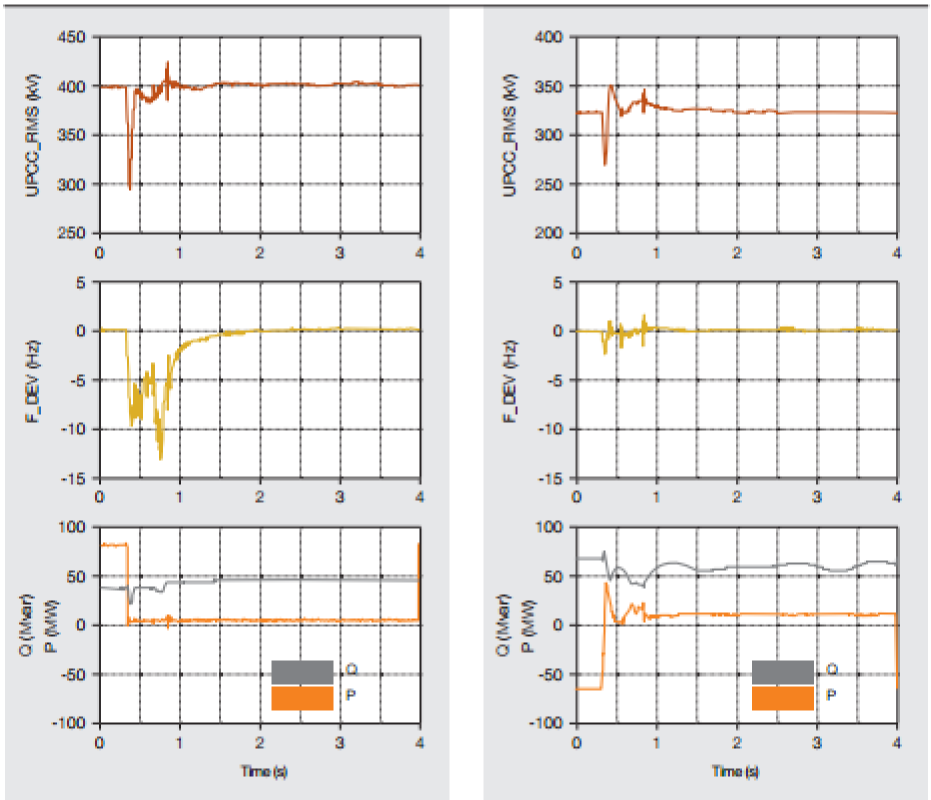

Figure 17: The power in the two ends in a HVDC cable between Namibia and Zambia. Namibia to the left and Zambia to the right. The left column shows the data related to the area that had a disturbance in its connected AC grid.

Emergency power

Today, HVDC links can provide frequency support by emergency power in the Nordic grid. Figure 18 shows the maximum contribution for some of the cables connected to the NSA. This is a constant contribution as long as the frequency is differs from the initial frequency [12].

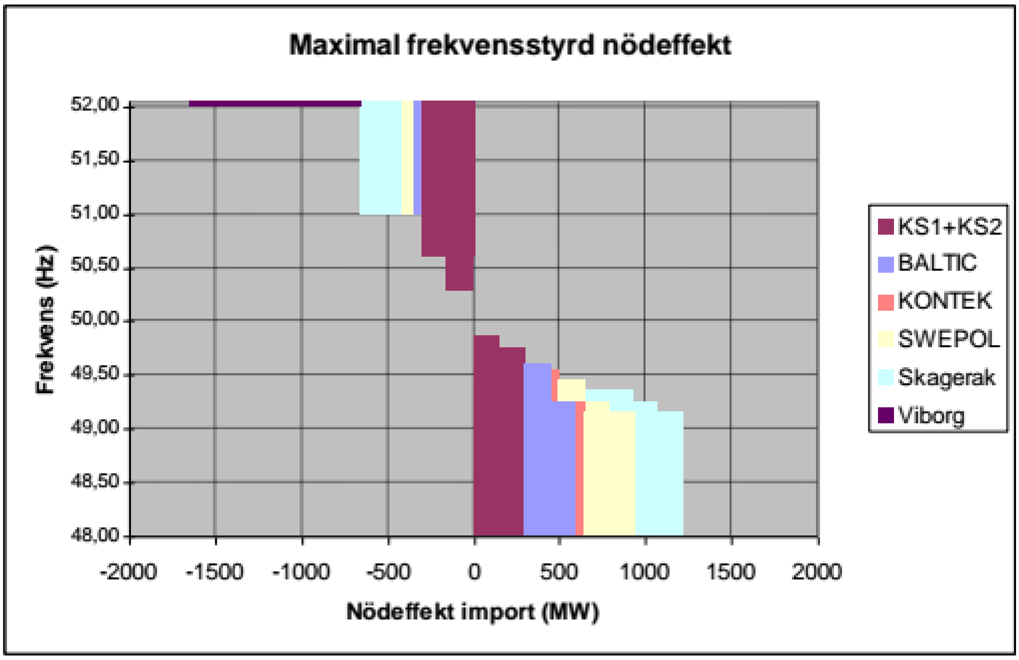

Figure 18: The contribution from the DC-cables connected to the Nordic synchronous area. During large frequency deviations, DC-cables can contribute with emergency power.

HVDC-links

The Nordic synchronous system gets a closer connection to other synchronous areas due to several newly built and planned HVDC cables. The transfer capacity to other areas is expected to increase by 53500 MW within 2020. Table 4 presents an overview of planned and existing cables in the Nordic countries [4].

Table 4: Existing and planned HVDC links connected to the NSA.

Cables from NSA		
Name	Capacity	Status
Norway (5200 MW)		
skagerak 1-3	1000	Built
norned	700	Built
skagerak 4	700	Built
norlink	1400	2018
NSN	1400	2020
Sweden (2640 MW)		
Konti -Skan 1-2	740	Built
Baltic Cable	600	Built
Swepol	600	Built
NordBalt	700	2016
Finland (2400 MW)		
EstLink 1-2	1000	Built
To Russia	1400	Built
Denmark (1200 MW)		
Kontek	600	Built
Storebælt	600	Built
Total	**11440**	

2.3.5 Small scale hydropower

Small-scale hydropower is assumed to increase its share in the Norwegian power system. Per definition, small-scale hydropower is hydropower plants with a rated power below 10 MVA. Small-scale hydropower stations currently do not have the same demands for turbine regulation as conventional hydropower, although this might change in the future. There are large uncertainties in regards to how small-scale hydropower will contribute to frequency support and how much this power source will contribute with system inertia. However, since most small-scale hydropower stations will be connected to the distribution network, the frequency support to the main grid from small-scale hydropower will be limited [4, 27].

3 MODEL

The model for the thesis is built into Simulink and is accompanied by scripts from MatLab. Hydraulic turbines and simple governing system is the main part of the model. The inertia is common for the entire system. Figure 9 from earlier shows the principal figure for this system. Figure 19 below shows a full principal block diagram that includes synthetic inertia and emergency power. The MatLab script that defines the variables is in appendix 1 together with the model from Simulink.

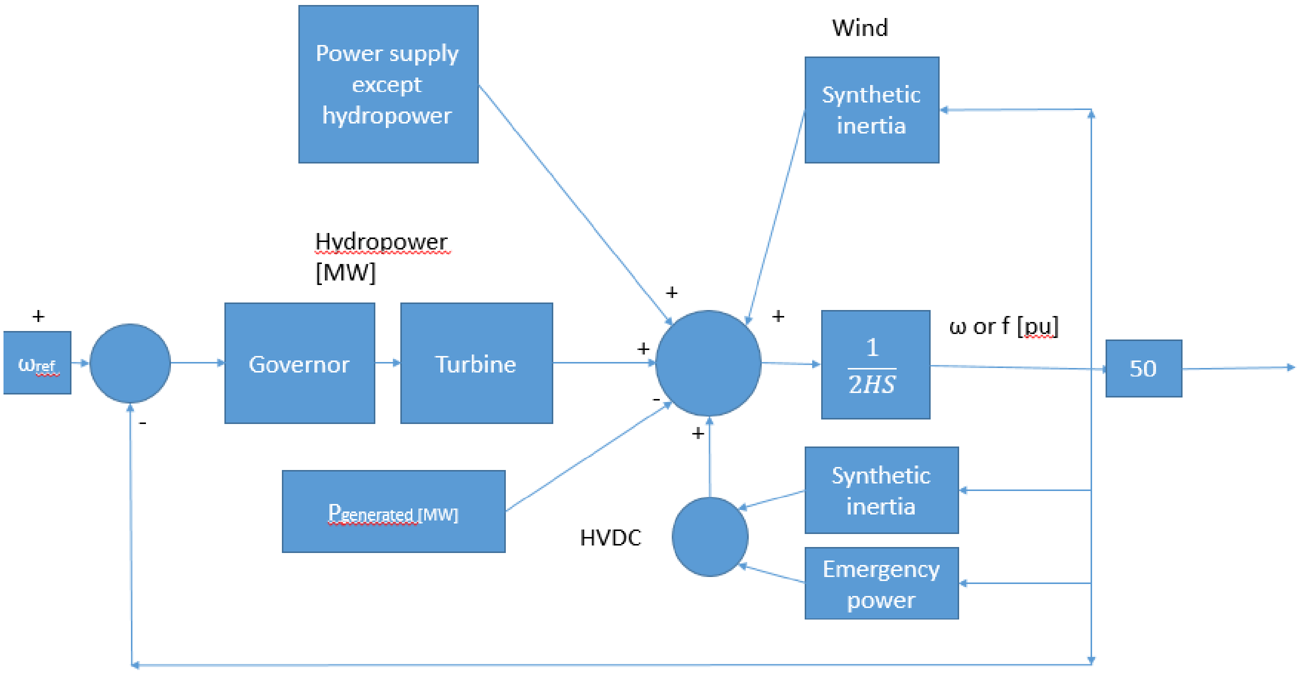

Figure 19: A full principal block diagram for the model with all synthetic inertia from wind and HVDC and emergency power from HVDC.

The governor and the turbine in the model only represent the energy production from hydropower. The remaining energy production that consists of nuclear, thermal, wind and HVDC contributes with inertia, but these production units do not have turbine regulation that provides FCR. The generation from these power sources is modelled as a positive load. If the HVDC were to export it would be modelled as a negative load.

However, synthetic inertia for both wind and HVDC has an extra power contribution instead of naturally inertia. HVDC power can also contribute to FCR and these additions to the model are explained below.

A full principal block diagram is shown in Figure 19.

Hydraulic turbines

In the hydraulic turbine, the energy is potential energy from a reservoir that lies H_s above the turbine level. H_s is the base-value for the system, and the turbine model therefor starts by a positive input of one. The friction in the tunnel and penstock is ignored, but the head loss is included and is presented in the model as *h*. Equation 10 is the starting point of the system. *dq/dt* is the change in flow, h_l is the friction loss that is zero in this model [6].

Equation 10

$$\frac{dq}{dt} = \frac{1}{T_w}(1 - h_l - h)$$

Figure 15 shows the block diagram for the turbine. The inputs for the model are c and Δω. c is the output from the governor and decides the opening of the valve for the turbine. The parameters in the turbine are kept to simple values to calculate with; the damping in the turbine is zero, the valve cross-sectional area AT is one, the starting time for the water T_W is one. T_W is the time it takes for the the flowrate to change by q_{base}. Q_{base} is the flowrate in the penstock at with the water gate fully open and the unit is m3/s. Tw is in seconds and is normally between 0,5 and 5 seconds. Qnl is the losses in the turbine and are ignored is this study.

The damping and the losses were tested with values different from zero. The results for the frequency graphs did not differ largely from each other. To keep the turbine simple, it was assumed that they could be zero.

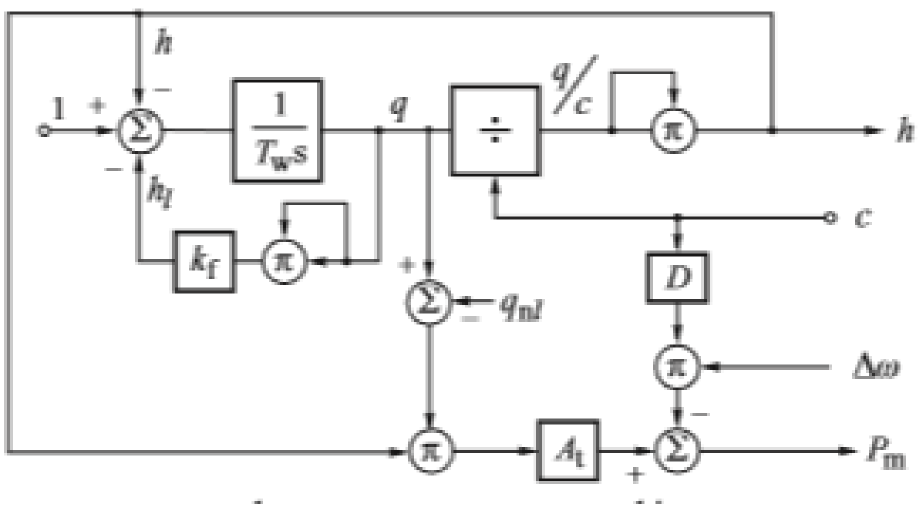

Figure 20: The block diagram for the turbine used in the model.

Governor

The governor is controlling the valve in the water reservoir. With information about the measured speed and the reference value of the speed, the governing system controls the turbine by adjusting the valve opening. If the rotational speed increase, the governor will reduce the valve opening, the turbine torque and the speed of the turbine will decrease. If the rotational speed slows down, the governor will increase the valve opening [6].

The governors in the system react to frequency deviation and change the production in proportion to the deviation. This is the primary control of the frequency in the power system. However, the governors for nuclear, coal, and gas do not respond to frequency deviation as well as the hydropower governors do [8]. However, outside the Nordic system, it is more normal for the governors for thermal and nuclear to react to frequency deviation. In reality, it is the governors for the hydro turbines that perform the primary frequency control in the Nordic synchronous system.

This thesis investigates the instant balance in the power system. In the model, governors only control the hydropower production. A positive constant represent all the other production units.

The governor is a PI-controller as Figure 21 shows. The input is the difference between the reference speed, and the real speed of the system in per unit values. The time constant T_i and the proportional gain K_P controls the signal given to the hydro turbines [28]. In the proportional term, the gain is multiplied with the magnitude of the error. In the integral term, the output is an integral of the error gained with the proportional gain. The reverse link contains the permanent droop for the system.

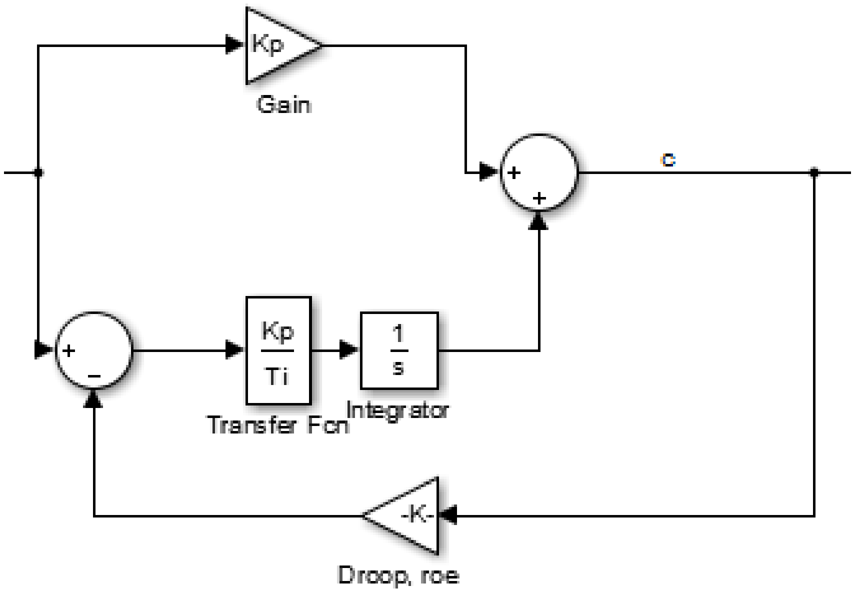

Figure 21: The governor model for hydropower in the power system.

Figure 22 and Figure 23 show respectively how the time constant and the gain effect the extra power production required when an outage occurs. The time constant is a time delay. By reducing the time delay, the system reacts faster to any disturbances and recovers the balance of the system. By reducing the time constant, the system reacts more strongly and more often to small disturbances. The gain increases the reaction of the disturbance. By reducing the gain, the system reacts slower.

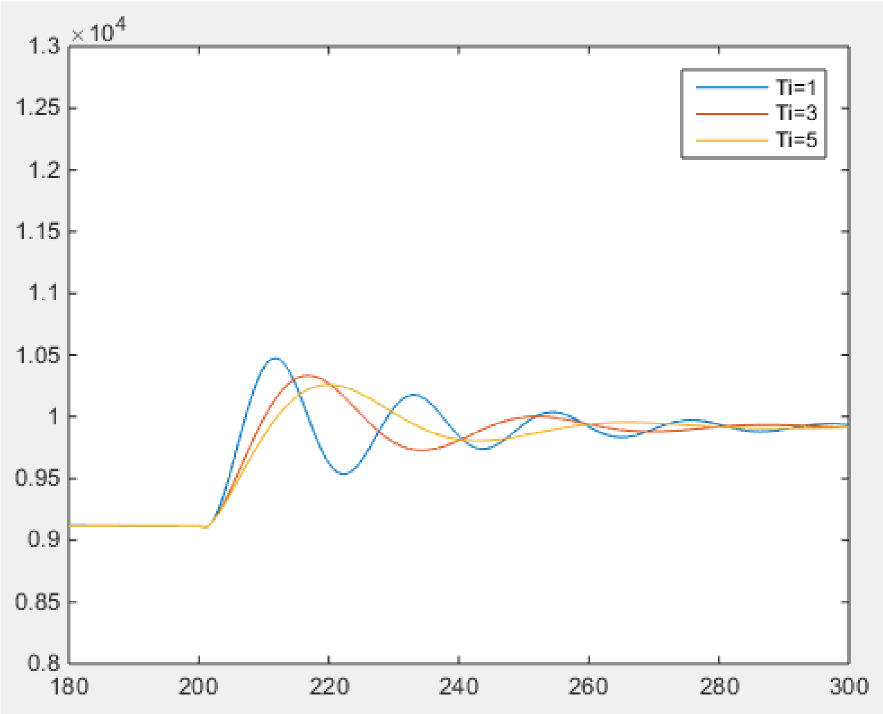

Figure 22: A lower time constant of the integral term provides balancing power faster, but the system becomes more unstable. The overshoot is also higher. The proportional gain is 3,1 and the droop is 8 percent.

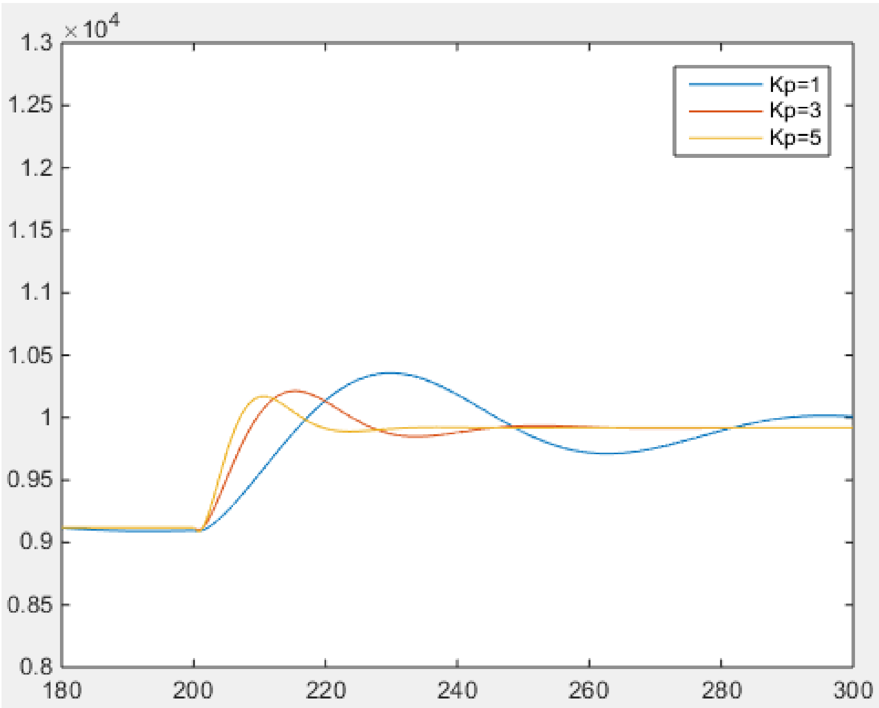

Figure 23: An increasing value of the gain activates the balancing power faster and the output stabilizes faster. Ti=5 and the droop is 8 percent.

Equation 11 shows the transfer function for the governor and Figure 24 shows the bode plot. The transfer function is general, but the bode plot is for the setting the governor normally has during scenario 2 and 3. Here, the droop is 8 %, the K_P is 3,1 and T_i is 5.

Equation 11

$$H(s) = Kp * \frac{T_i s + 1}{T_i s + K_p * \rho}$$

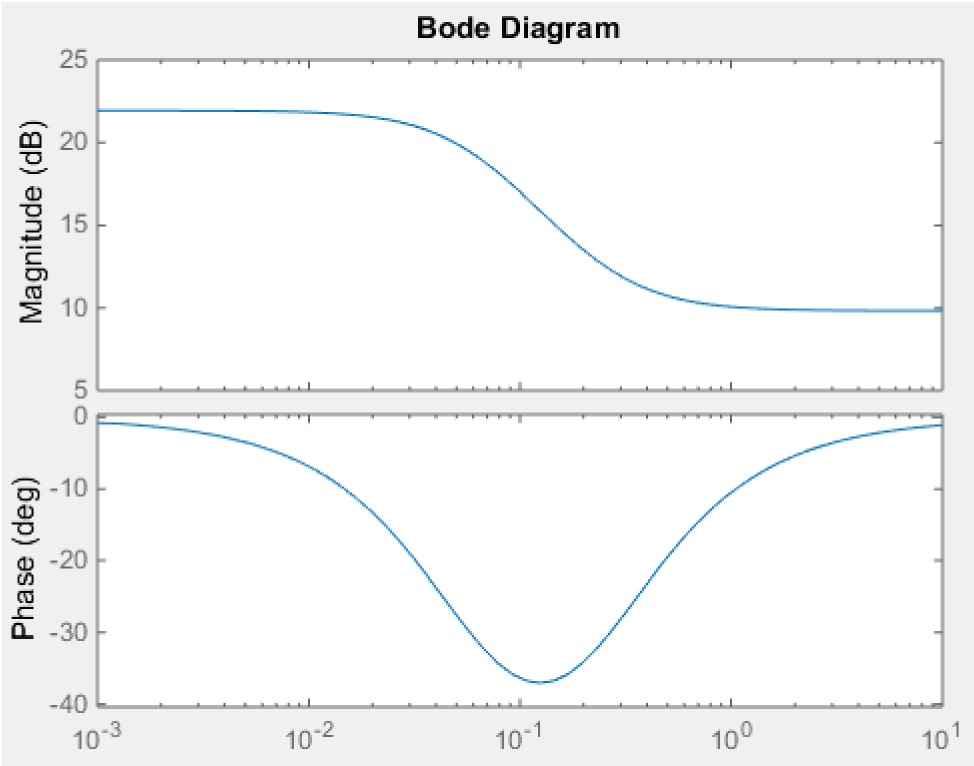

*Figure 24: Bode plot for the governor when Kp=3, Ti=5 and the droop is 8 percent. The starting gain is 20*log(1/0,08).*

The bode plot in Figure 24 shows the how the governor responds to the different input signals. For higher frequency deviations, the signal is not that strong to reduce the oscillations.

Inertia

Equation 12 shows the system equation. This shows the balance between the generated power, the load and the damping power. This is rewritten from In Equation 12, H_{sys} has the annotation Gigawatt-seconds and not seconds. The inertia constant in watt-seconds is the actual amount of kinetic energy in the system. The damping power is zero to simplify the model.

The equation is the output from the model, and is further transformed to the frequency in the system. P_D is zero, P_{load} is the electric energy, and P_G is the physical energy in the system.

Equation 12

$$\omega = \frac{1}{2 * H_{sys} * s}(P_G - P_l - P_D)$$

System detail from the NORDIC-44 model

A similar study was performed at the NORDIC-44 model form PSSE[4]. That model did not include Denmark in the Nordic synchronous area. Therefore, Denmark was also omitted from this study.

3.1 Model with synthetic inertia

The model contained synthetic inertia for the simulations regarding the power system in 2020. Figure 26 shows the loopback that was added to the model to make the system provide synthetic inertia in case of a frequency disturbance.

Figure 25 shows the principal drawing of the synthetic inertia model that is added to the main model for studying this concept. This controls the output signal according to the derivative of the frequency change. Since synthetic inertia is unsymmetrical, it only responds if the derivative is negative. When Δf is stable, there will be no contribution from synthetic inertia. The dead band limits set the starting point for the synthetic inertia. This is the actual frequency deviation, and not the derivative of it. The gain, K_{wi}, reinforce the signal, the washout filter eliminates frequency levels that should not start the activation of synthetic inertia.

According to GE[5] a good starting point for the variables in the model is to set the gain K_{wi} to 10 and T_{wowi} to 5,5. The filter with Twi is included in a different way in Simulink. The starting point for the synthetic inertia is suggested by GE to be at 49,875 Hz. In the model this was implemented to start at 49,9 Hz, together with the activation of the FCR-D reserves. The tuning of the synthetic inertia is shown later.

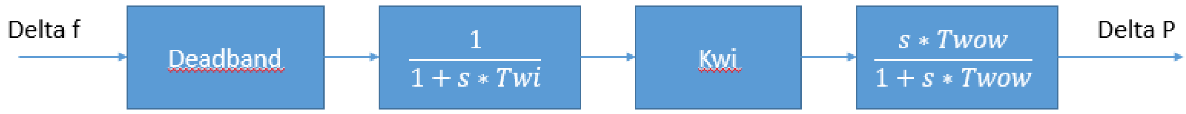

Figure 25: The principal block diagram used in the model.

Figure 26 shows the model made in Simulink. The first block eliminates frequencies over 49,9 Hz, and outputs the difference between 49,9 and the system frequency. The second block or the summation point finds Δf by adding 0,1 Hz, which differs 49,9 Hz from 50 Hz. Afterwards comes the proportional gain, which boosts the frequency, and transform the frequency signal to an active power contribution. K_{WI} is given in MW/Hz. The washout filter is the block with the transfer function, and eliminates stable frequency deviations. The saturation block limits the output to maximum 0,1 or 10 percent. The result is then multiplied with the original wind power production. 10 percent is the maximum with which the wind turbine can immediately change its production to contribute with synthetic inertia.

To have the input as Δf instead of f is not really necessary, since the synthetic inertia looks at the derivative of the input. The derivative of Δf and f is the same.

[4] PSSE is a simulation program for more detailed studies regarding the power grid.
[5] General Electric, producer of windmills.

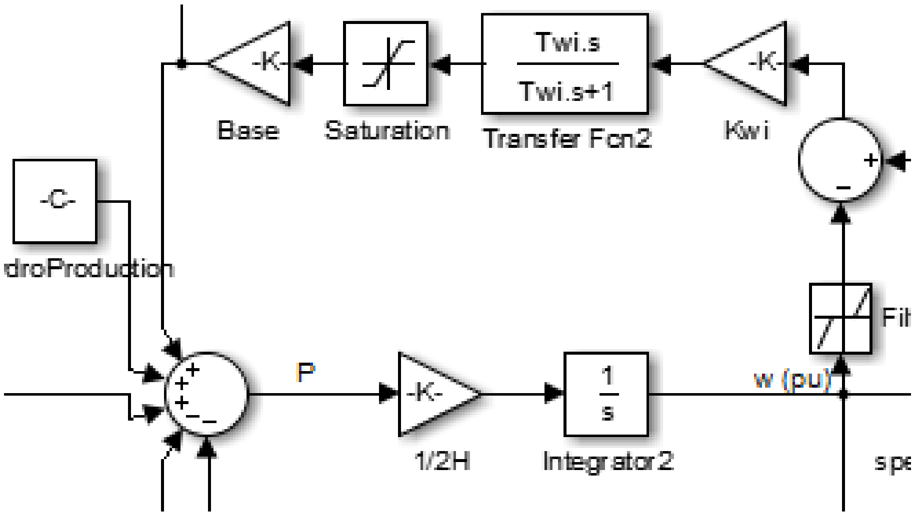

Figure 26: The loopback added for the model with synthetic inertia.

3.2 MODEL WITH HVDC

Emergency power and synthetic inertia from HVDC is not a topic with many published research papers. Therefore many assumptions had to be made. Synthetic inertia from HVDC is therefore modelled as the synthetic inertia from wind without the recovery energy.

The model for HVDC that provides emergency power is a simple loop that contributes with extra power when the frequency drops below 49,8. After that it contributes with a power amount proportional to the frequency deviation between the system frequency and 49,8 Hz. Furthermore, a time delay and a filter are used to avoid to large oscillation when starting the emergency power.

The first block, in reverse direction, only allows frequencies that deviates more than 0,2 Hz from 50 Hz, to pass through the loopback. The output is the deviation to the lower or upper limit. If the frequency 49,5 enters, the output is 49,5-49,8=-0,3. The second block outputs the deviation to 49, 8 Hz or 50,2 Hz in a positive number. The third block removes all frequency deviation above 0,6 Hz, the third block is the proportional gain, the fifth block transform the input from per unit values to active power in MW, and the LTI system block in the end is the filter with a time delay. This filter will be introduced later.

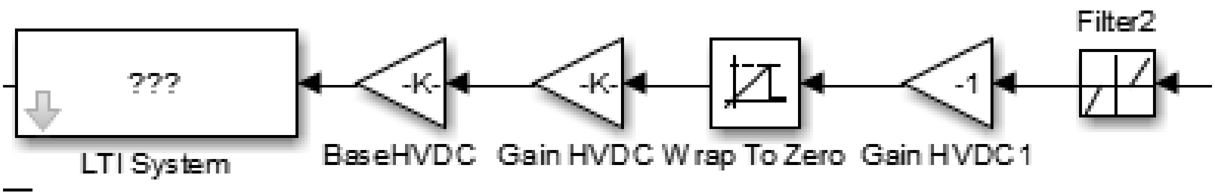

Figure 27: The model added for emergency power from HVDC

The testing of the filter and the proportional gain is presented in 5.4.4 Test of the synthetic inertia and the emergency power from HVDC.

4 METHOD

The results from the simulation are categorized and tested in three scenarios for the energy situation.

1) Reference scenario
2) Low load scenario
3) Future scenario

The reference scenario tunes the model to react like the synchronous system. Data from a real disturbance is plotted in MatLab together with the model. The parameters in the model were adjusted to make the frequency response after tripping an 1100 MW production unit the same for the model as for the real system. This is also the introduction to how the different parameters are calculated in the following scenarios.

Scenario two tests the limits for the dimensioning incident in todays system at a critical operating point from June 23rd 2013, when the load in the Nordic synchronous area was 22038 MW. The goal for this scenario is to find the maximum loss of production the system can withstand during low load with traditional production like Hydro, Thermal and Nuclear. The effect of changing the settings of the governor is also tested. The second scenario also aims to map how the total production amount and portfolios of the production affect the dimensioning incident. This is originally a low load scenario. Firstly, the portfolios are changed, and afterward the production is increased step by step. This scenario does not change the wind contribution.

Scenario number three looks at a future scenario for 2020, which Statnett has developed as a worst-case scenario for 2020. The total energy supply in this scenario is 22661 MW, which do not differ much from the scenario from 2013. An increasingly share of wind, HVDC and small scale hydropower is the basis for the scenario.

The unknown variables that are calculated for each scenario are the connected apparent power, the amount of synthetic inertia and the production portfolio of different producers.

The script for one scenario is found in Appendix 1.

By these scenarios the following problems will be the main focus during the analysis:

1) How can the frequency response be changed and what parameters and assumptions affects it.
2) What will the dimensioning fault be in the future.
3) Will the demands for FCR-D also provide the needed amount of kinetic energy in the system.

4.1 LIMITATIONS FOR THE STUDY

The model represents the balance between physical and generated electrical power. This is a very simplified model that can demonstrate the effects different parameters have on the frequency stability in a system. It can show how changing the regulator's settings, the system inertia, the power balance and the influence of new technologies can be reflected in the system frequency during a disturbance.

However, the model has several central limitations regarding power system stability.

The model only considers one of the three main categories in power system stability – frequency stability. Voltage stability and rotor angle stability is not revised, but will have huge effects on the system during large disturbances.

The hydropower that provides FCR is modelled as one large machine. In reality, the machines can oscillate against each other and cause further instability in case of a large disturbance. At the most, there are oscillations from synthetic inertia from wind and HVDC, emergency power and hydropower at the same time in this model. These effects are not modelled and are not uncovered as sources for instability in the model.

The model is linear unlike the real power system.

The system represents the first reaction systems have after a large fault occurs. FCR-N and FRR are therefore not considered in the study.

4.2 REQUIREMENTS FOR THE FREQUENCY

From the system operation agreement [12]. the following list is made to control the frequency in the scenarios.

To find a safe operating point:

1) The frequency must never drop below 49 Hz.
2) The frequency must never stabilize at any lower frequency than 49,5 Hz
3) The FCR-D demand is divided into three categories
    a. 50 % of the size of the power imbalance must be compensated for within 5 seconds.
    b. 100 % of the power imbalance must be compensated for within 30 seconds.
    c. The frequency bias must be at least 3000 MW/Hz.

Point 2 is interpreted as a requirement for the stable frequency after FCR-D is fully activated. The system operation agreement does not make this clear, but other documents specifies that the 49,5 Hz requirement is valid for the stable frequency [29]. The lowest transient frequency was not explicit mentioned in the system operation agreement, but we assume that the transient frequency can go to 49,0 Hz [15].

Another point that is changed from its original form is point 3c. The requirement is that 1200 MW will start to activate at 49,9 Hz and should be fully activated at 49,5 Hz. This results in a required frequency bias of 3000 MW/Hz.

Requirement 2 and 3c can be controlled by the droop, since the droop decides the stabilizing value. This has not been a focus, so these factors are registered, but not investigated further. The study focuses on the dynamic response after a disturbance.

4.3 ASSUMPTIONS AND CHOICES FOR THE SCENARIOS

Several factors were not investigated properly, so several assumptions were made to conduct the simulations. Some choices also had to be made to restrict the scope of the thesis.

Droop and start frequency

In the reference scenario, the droop in the governor is found to be 12 percent. However, the study is mainly conducted to find the absolute limits. To ensure a stable frequency, the droop is lowered to 8 percent since this can be done by existing marked structures. It also seems reasonable to lower the droop or increase the frequency bias during a low load scenario.

However, this study mainly looks into the dynamic part of the response. There are well functioning systems that can purchase droop to have a better frequency bias. The droop can be lowered to 4 or 2 percent, but this is not done in the study.

The start frequency is set to 49,9 Hz in the later scenarios. This is because it is the FCR-D reserves that are mainly tested and the activation of these reserves starts at 49,9 Hz. Also, the system should withstand the dimensioning incident with a start frequency at 49,9 Hz. The demand for FCR-N is to react within 2-3 minutes. The frequency must withstand the dimensioning incident with an initial frequency at 49,9 Hz.

Synthetic inertia from wind power

The main assumptions for wind power were that all the windmills that deliver energy, also can provide synthetic inertia. The available amount of energy the synthetic inertia can deliver is assumed to be 10 percent of the original production all the time. Since the synthetic inertia reacts to the derivative of the frequency deviation, the power support from synthetic inertia will finish when the frequency deviation stops increasing. It is assumed that this increase will stop before the available "reserves" for synthetic inertia is fully utilized.

HVDC – Synthetic inertia and emergency power

To model the contributions from HVDC-cables during low frequency events, several assumptions were made due to lack of published work regarding HVDC and frequency support. Modern HVDC cables can contribute to both synthetic inertia and emergency power.

Emergency power

The possibilities for emergency power supply for 2006 was presented earlier. To make a similar graph for 2020, a linearization is necessary. It is assumed that at the point [0 , 49,8] from the graph from 2006 is stable in the model. At the most, the emergency power is 2006 could deliver 1200 MW with emergency power. The power part of the point [1200 , 49,2] will increase to 2000 MW. The cables in 2006 have a rated capacity for 4940 MW. This makes the maximum emergency power to 24 percent of the total capacity. With a transfer capacity of 11440 MW in 2020, the assumption is that emergency power can be 2778 MW or 24 percent of total transfer capacity.

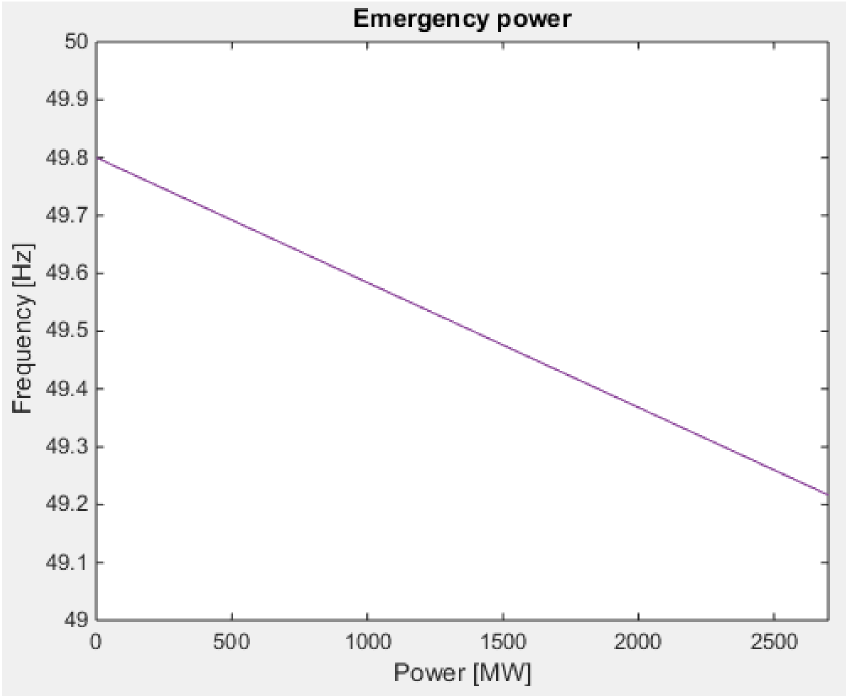

Figure 28: The assumed emergency power capacity in 2020.

Possible limitations at the sending end of the HVDC connection are not taken into account.

Equation 13 calculates the stiffness of the emergency power supply. The emergency power is modelled as FCR support, but will not contribute during the transient period. Emergency power and FCR are not the same, but it is modelled like this.

Equation 13

$$K = \frac{\Delta P}{\Delta f} = \frac{2778 - 0}{49{,}8 - 49{,}2} = 4630\ MW/Hz$$

However, there must be transfer capacity available.

Synthetic inertia

The synthetic inertia for HVDC was modelled the same way as wind power due to lack of information about modelling inertia for wind power.

5 SCENARIOS AND RESULTS

5.1 SCENARIO 1 – REFERENCE SCENARIO

The reference scenario is from March 5th, 2015 when a production unit that produced 1100 MW tripped. Figure 29 shows the frequency response during this incidence. This scenario is the basis for adjusting the governor and the system details, so that the model responds to this disturbance in a similar way as in Figure 29.

Figure 29: The frequency response on March 5, 2015, when the system lost 1100 MW production. This is data from Statnett.

The model in Simulink represents and calculates at all time the balance between mechanical and electrical power. Therefore, the load in the model is not the consumption of electricity, but the production of electrical energy. In addition, as mentioned earlier, Denmark is not a part of the study. The load in the model is 52471 MW, which is the production in Norway, Sweden and Finland in Table 5.

Table 5: Production and consumption of electric power on March 5th, 2015 from 11.00 to 12.00 according to NordPool.

	Production(MWh/h)				
	Norway	Sweden	Finland	Denmark	Nordic
Production	23 089	20 723	8 659	4 311	56 781,00
Consumption	18 639	19 768	10 831	4 921	54 158,00

Table 6: Production of electric power the 5th March 2015 from 11.00 to 12.00 according the transmission system operators FinGrid, Svenska Kraftnät and Statnett.

	Production(MWh/h)					
	Nuclear	Hydro	Thermal	Wind	Solar	Total
Finland	2743,00	2154,00	3808,00	8,00	0,00	8713,00
Sweden	6677,31	11924,40	1192,90	143,85	12,88	19951,30
Norway	0,00	22778,21	376,13	268,78	0,00	23423,12
	9420,31	36856,61	5377,03	420,63	12,88	52087,4225

In this scenario and according to Table 6, hydropower comprises 36858 MW (70,7 %) of the total production. The synchronous machines that provides hydropower, also provides the frequency containment reserves. Thermal and nuclear production units provide support to FRR, but the model does not include these reserves.

To adjust the model, the most efficient way was to adjust factors during the simulations, and continuously compare the modelled response to the real response. However, the calculations gives indications for each factor.

Calculation of the droop

A rearranged form of Equation 1 calculates the droop of the system. Equation 14 shows the rearranged form of Equation 1 and Equation 15 shows the calculations for scenario 1. The parameters of the equation is the amount of connected hydropower P_n, the stable frequency change Δf, the size of the disturbance ΔP and the nominal frequency f_n. To find the amount of connected hydropower capacity, it is assumed that the hydropower stations are running at 80 percent load, and that the power factor is 0,9. Therefore, the current production from hydropower, which is 36858 MW, is divided by 0,8 and 0,9. This results in 51189 MW. It is important to notice that this is an assumed number.

The lost production is 1100 MW. Figure 29 shows that the stable frequency change is 0,13 Hz, and that nominal frequency of the system is 50 Hz.

Equation 14

$$\rho_{i=} - \frac{P_{ni} * \Delta f}{\Delta P_{mi} * f_n}$$

Equation 15

$$\rho = \frac{51189\ MW * 0{,}13\ Hz}{1100\ MW * 50\ Hz} = 0{,}12$$

The calculation shows that the droop of this system is 12%, which is a reasonable result. The droop normally is in the interval from 4 % to 12 % [22].

Calculating the inertia

Equation 16 shows a rearranged form of the swing equation. Below is the calculations that gives us an approximation of the amount of inertia in the system. Equation 16 is a rearranged form in real numbers, and not in per unit values, and gives the amount of inertia. $\frac{df_i}{dt}$ is the tangent from the frequency drop when the outage occurred. This is shown in Figure 30.

Equation 16

$$H * S = \frac{\Delta p_i * f_n}{2 * \frac{df_i}{dt}}$$

$$H * S = \frac{1100\ MW * 50\ Hz}{2 * \frac{0{,}4\ Hz}{5\ s}} = 343750\ MWs = 344\ GWs$$

The above calculation shows the assumed amount of kinetic energy. 1100 MW is the size of the disturbance, 50 Hz is the system frequency, and 0,4 Hz divided by 5 seconds is the tangent of the first fall of frequency. Figure 30 shows this situation

During the adjustment of the model, to make it is as similar as possible to the real frequency response, the amount of kinetic energy was adjusted to be 370 GWs.

To find the inertia constant, the amount of kinetic energy is divided by the connected power at the operation point. As mentioned, it is assumed that hydropower is running at 80 % load. Nuclear and thermal are assumed running at full load but are divided by the power factor, 0,9. Solar and wind are ignored in this case, since they don't contribute with kinetic energy. Equation 17 shows the calculation of the connected power.

Equation 17

$$S_{sys} = \frac{36586}{0{,}8 * 0{,}9} + \frac{9420 + 5377}{0{,}9} = 67631{,}2\ MW$$

By dividing the total amount of kinetic energy by the connected power, we find the inertia constant. 370 GWs divided by 67,7 GW is 5,47 s. This is the systems inertia constant.

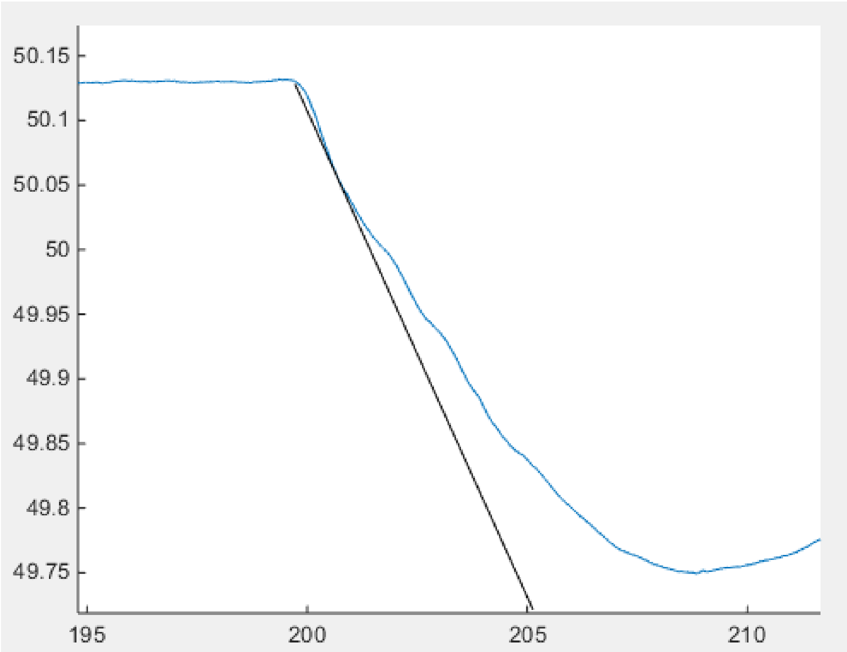

Figure 30: Frequency dip in the reference scenario.

Unknown variables

By adjusting the variables in the model, the frequency response from the model became almost similar to the frequency response in the power system. Table 7 shows all the variables and their values in the reference scenario. Figure 32 shows the frequency response.

T_D and T_P are time constants in a filter before the governor. The transfer function for the filter is presented below and the bode plot in Figure 31. T_D increases the oscillations and T_P did not have much effect on this system.

$$H(s) = \frac{1 + T_D s}{1 + T_P s}$$

Table 7: Values of all the variables in the model for the reference scenario.

Constants of the model	
Governor	
Kp	2
Droop	0,12
Ti	5
Td	0,1
Tp	0,9
Turbine	
D	0
Tw	1
Qnl	0
At	1
System coefficients	
Damping	0,4
Sbase [MW]	51189
Inertia [MWs]	370000
Inertia constant [s]	5,47
Wsync	2*pi*50

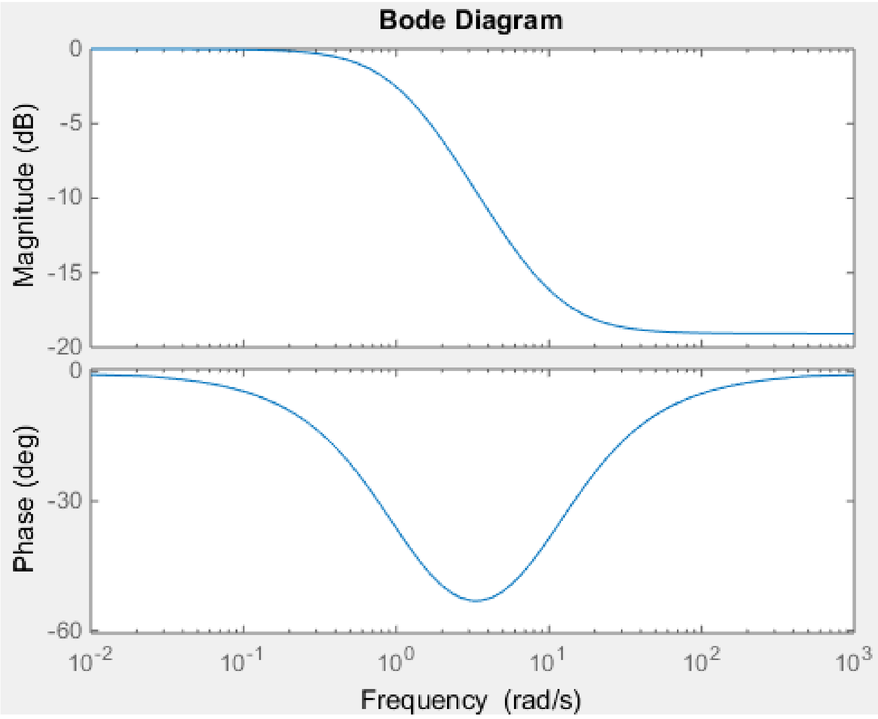

Figure 31: Bode plot for the filter in the governor.

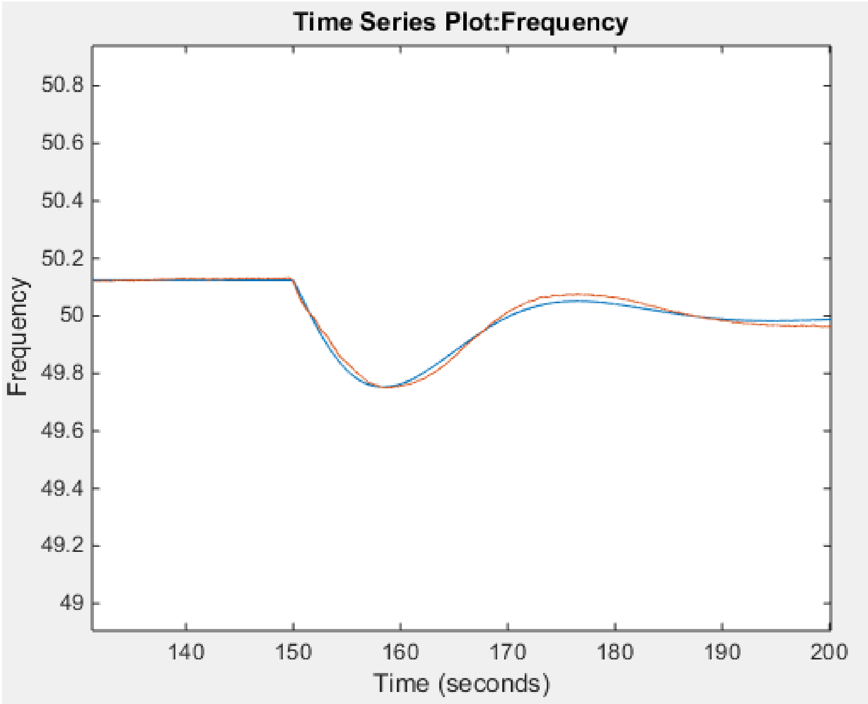

Figure 32: The response from the real power system and the response from the model. The blue line is the real response and the red line is the response from the model.

Frequency containment reserves

The frequency containment reserves for disturbances (FCR-D) must be at least 3000 MW/Hz. In this case it is an increase in production by 1100 MW, and the frequency fall is 0,13 Hz. Equation 18 shows that the amount of FCR-D is 8413 MW/Hz. The demand for FCR-D is fulfilled.

Equation 18

$$\frac{1100}{0{,}13} = 8413\ MW/Hz$$

5.2 Execution of the scenarios

The coming scenarios are used to test different properties for the system during different operating conditions. All the systems are at low load.

The executions of the scenarios are done with the following method:

1. Each scenario has a several varieties. The production portfolio, the system inertia and the settings for the governor can change. The future scenario includes wind, HVDC and small-scale hydropower is different ways.
2. The different production portfolios change the system inertia.
3. If the hydropower is changed, the amount of FCR changes.
4. At all the varieties, it is found how much production that must be lost to decrease the frequency to 49,0 Hz in the transient period,.
5. At this scenario, the demands for FCR are looked at, it is registered if they satisfy the current demands or not.
6. The loss of production that satisfy all the demands, or at least the demand to keep the frequency above 49,0 Hz at all time, is the maximum dimensioning incident that system can withstand.
7. It is tried to change the system to see how the maximum fault the system can withstand changes with the different parameters.

5.2.1 Scenario 2

Scenario 2 is a low load scenario from 2013 with conventional power sources. The scenarios have several alternatives, and explore how the system can have different operating conditions to meet the requirements for the transient response after a disturbance.

A. This alternative looks how the principal relation between amount of system inertia and fault the system can withstand. In this scenario, the parameters found in the reference scenario are not changed.
B. The alternative explores the effect by changing the settings for the governor in the hydropower. This will affect the frequency response and the fault the system can withstand. These relations are documented in 2B.
C. Scenario C explores the effect of difference production portfolios. The composition of the conventional power sources is changed and the fault the system can withstand is found.
D. This alternative explores the effect and the relation between the system's ability to withstand fault compared to an increase in total production.

5.2.2 Scenario 3

Scenario 3 is a worst-case scenario that has been developed by Statnett, and the concern for reduced system inertia has been especially emphasized. The affects the new power sources have on the system stability are explored.

A. This scenario looks into integration of wind. This explores the effect of synthetic inertia form wind as a part of the frequency support during low load.
B. 3B looks into the same scenario as 3A but replaces some of the conventional hydropower with small-scale hydropower. This scenario looks especially into the requirement of 50 percent provision of the lost power after 5 seconds. By reducing the conventional hydropower, the requirements of FCR-D are crucial.
C. This scenario looks into synthetic inertia and emergency power from HVDC. This also combines wind and HVDC in different ways, to show how the responses interact with each other.

5.2.3 Sensitivity analysis

There are several ways of conducting an analysis like this. In the sensitivity analysis, the findings from the reference scenario are interpreted in a different way. Scenario 2C and 3A are done one more time with new assumptions to show how the results are affected by this.

5.3 Scenario 2 - Low load and small production – adjusting the system

The 23rd of June 2013 in the early morning between 05.00 and 06.00 the load in the Nordic countries was exceptionally low. This hour is the starting point for Scenario 2, which tests the limit for the system by adjusting and exploring the effects of different factors.

Table 8: Production of electric power the 23rd of March 2015 from 05.00 to 06.00 according the transmission system operators FinGrid, Svenska Kraftnät and Statnett.

	Production(MWh/h)					
	Nuclear	Hydro	Thermal	Wind	Solar	Total
Fingrid	2706	739	1205	29	0	4679
Sweden	7421	2414	258	772	0	10865
Norway	0	5965	391	138	0	6494
Total	10127	9118	1854	939	0	22038

The load in the model is set to 22038 MW, and a step increase of 1100 MW is introduced after 200 seconds. 200 seconds is used to make sure that the system has stabilized after the initialization. The hydropower can increase the production with 20 percent, if there is need for spinning reserves.

The production in the system is 22038 MW, and in this case it is assumed that nuclear and thermal work at full load and hydropower at 80 percent, like in the reference scenario. Equation 19 calculates the amount of kinetic energy for scenario 2.

Equation 19

$$H * S = 5{,}47\ s * \left(\frac{9118\ MW}{0{,}8 * 0{,}9} + \frac{10127 + 1854}{0{,}9}\right) = 142{,}1\ GWs$$

5.3.1 Alternative 2A – changing the inertia for an improved response

The electrical power production was the only thing changed from the reference scenario in the first simulation in alternative 2A. The loss of production is constant at 1100 MW, the droop and the inertia-constant are not changed. The amount of inertia is lower due to reduction in connected power. The initial frequency was 50 Hz, and after the tripping of a production unit, the frequency dropped to 48,7 Hz. This frequency is not acceptable and means that the reserves are not sufficient to withstand the fault. By reducing the size of the outage to 900 MW, the frequency dropped to 49,0 Hz. This is the lowest acceptable level in the Nordic system.

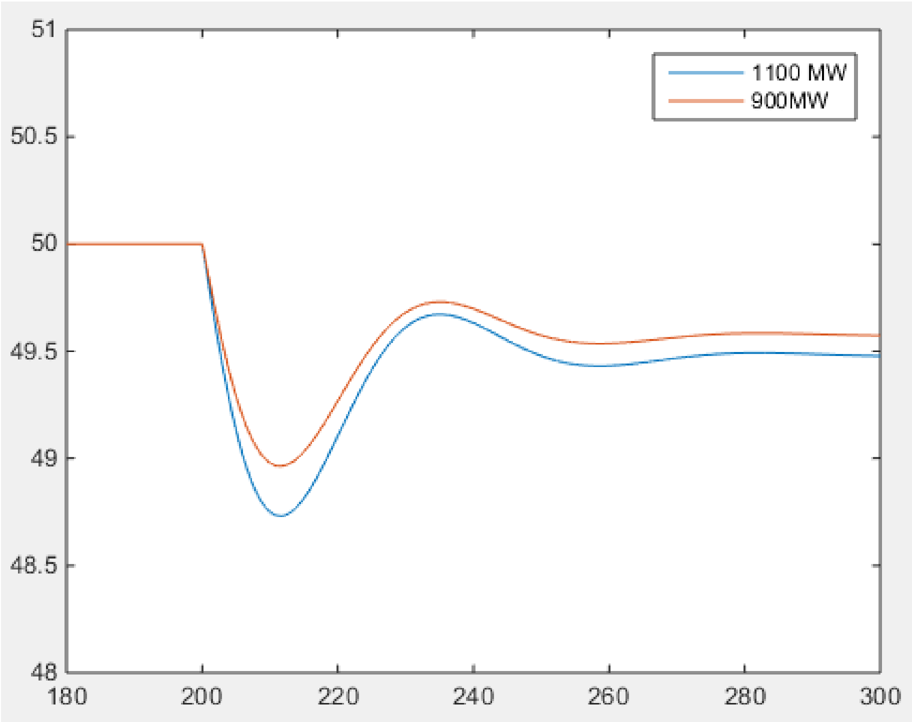

Figure 33: The frequency response in the low-load scenario, alternative A.

The frequency bias is calculated below, and this is done by using Equation 3.

$$\frac{900}{50{,}00 - 49{,}57} = 2093\ MW/Hz$$

The relation between the dimensioning incident and the amount of kinetic energy is investigated further. The lack of frequency containment reserves is ignored for the time being.

The minimum frequency the system can accept for all incidents are 49,0 Hz during the transient period. The initial frequency is now moved to 49,9 Hz, since this is the lowest value that is considered to be normal operation. Figure 34 shows the relation between the dimensioning incident the system can handle, and the need for inertia and kinetic energy in the system. The total production is kept low, and the amount of kinetic energy is simply increased without taken synchronously connected power or the inertia constant into consideration. Figure 21 shows a principal study of inertia related to a low load scenario, and the production portfolio is not changed, only the amount of kinetic energy.

The possibility to increase the inertia without changing the production portfolio is discussed later.

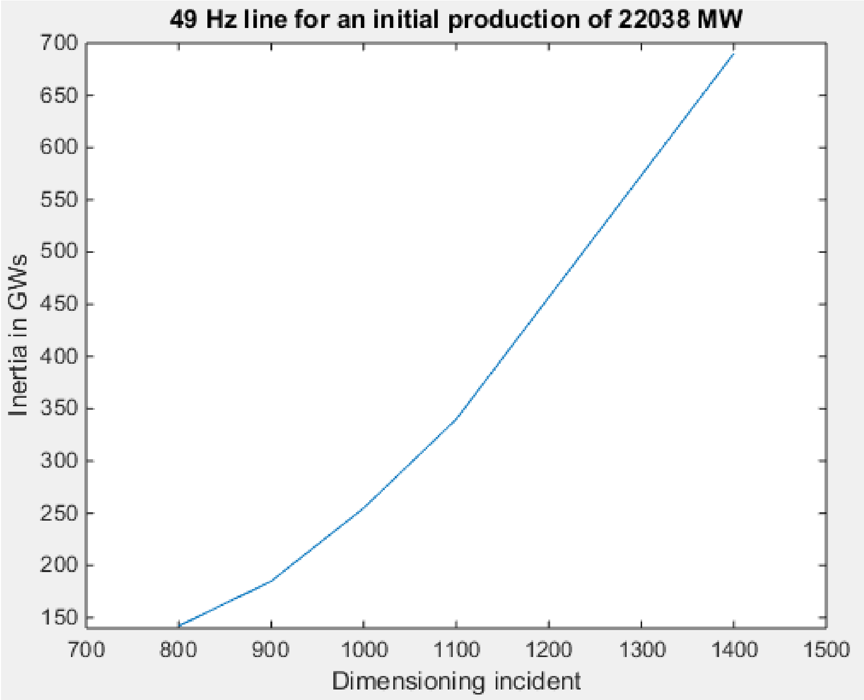

Figure 34: The 49 Hz line for an initial operating point at 22038 MW.

5.3.2 Alternative 2B – changing the system factors for an improved frequency response

Alternative 2B explores the frequency response for different dimensioning incidents. The requirements regarding frequency containments reserves for disturbances (FCR-D) limit the dimensioning incident in some cases, and these effects are studied. Figure 35 shows the frequency response for an outage where the production is the same as in alternative 2A, and the amount of lost production is 800 MW. The initial frequency is 49,9 Hz, and it stabilizes at about 49,63 Hz. Figure 36 shows the power output from the hydropower after the disturbance.

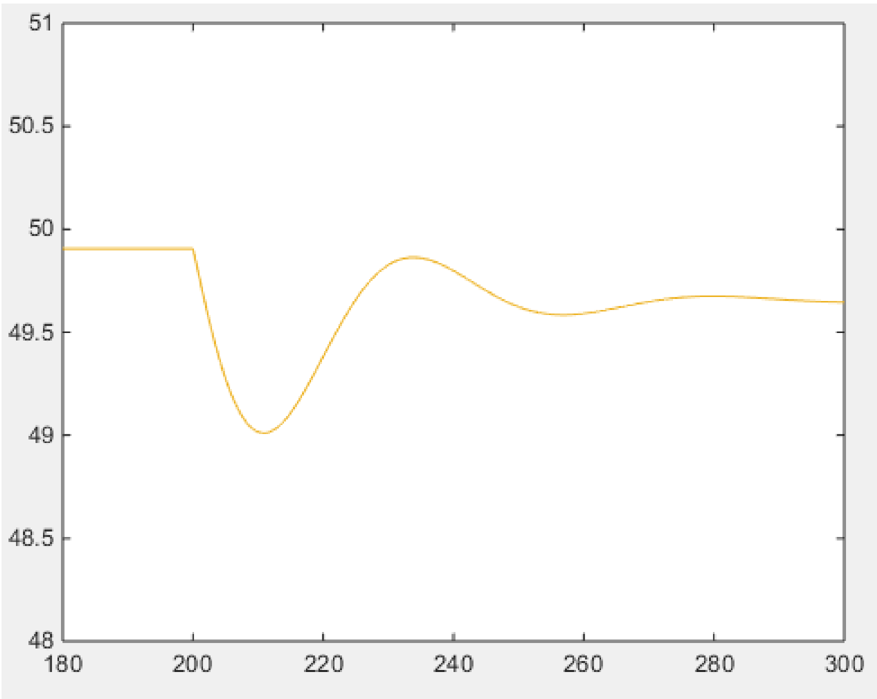

Figure 35: The frequency response for a loss of 800 MW production.

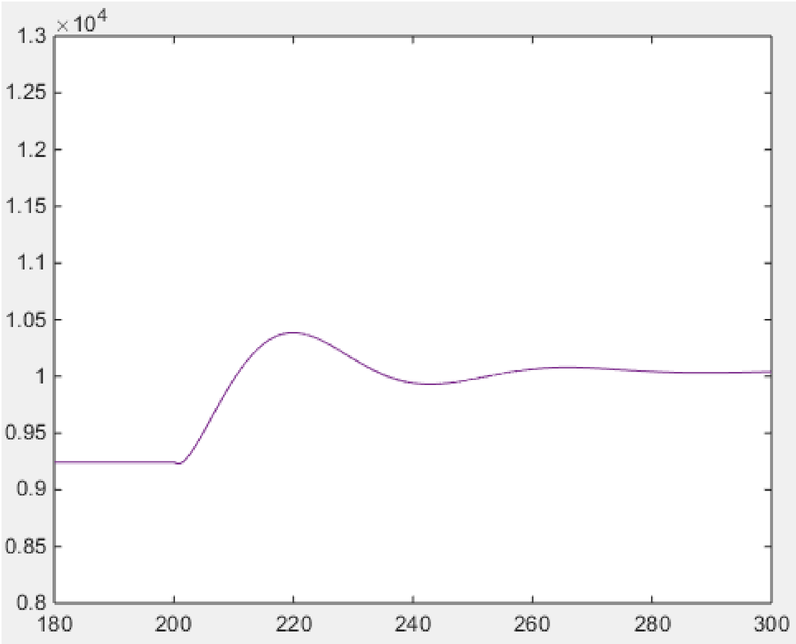

Figure 36: The power output from the hydropower stations.

Five seconds after the incident, the hydropower stations produce 9389 MW. Before the incident, the production was 9118 MW. This makes the system provide 271 MW within 5 seconds. According to the demand for FCR-D, the production should have increased by 400 MW, which is 50 percent of the lost production. This scenario does not satisfy these demands. After 30 seconds, the production has a peak and produces 1003 MW. This satisfies the FCR-demand of 100 percent activation of the FCR-D within 30 seconds. The production at this point is at a peak level, and is not stable.

Changing the response

To improve situations in the case of fault occurs, different factors can change. However, only some are realistic to change. Hydropower is the only power source that provides FCR in the model. Increasing the share of hydropower in the power supply will therefore increase the amount of FCR and improve the frequency bias and the dynamic response after 5 seconds. This test is performed in Alternative C. In this scenario, the focus is on changing the control mechanisms in the governor to improve how the system reacts to an incident.

First, the size of the fault is tested. Figure 37 shows that it has little effect on the power supply after 5 seconds. This is not surprising since the gain is proportional to the frequency change. The frequency deviation is dependent on the amount of lost production. Therefore, changing the fault will not contribute to a better FCR-D response.

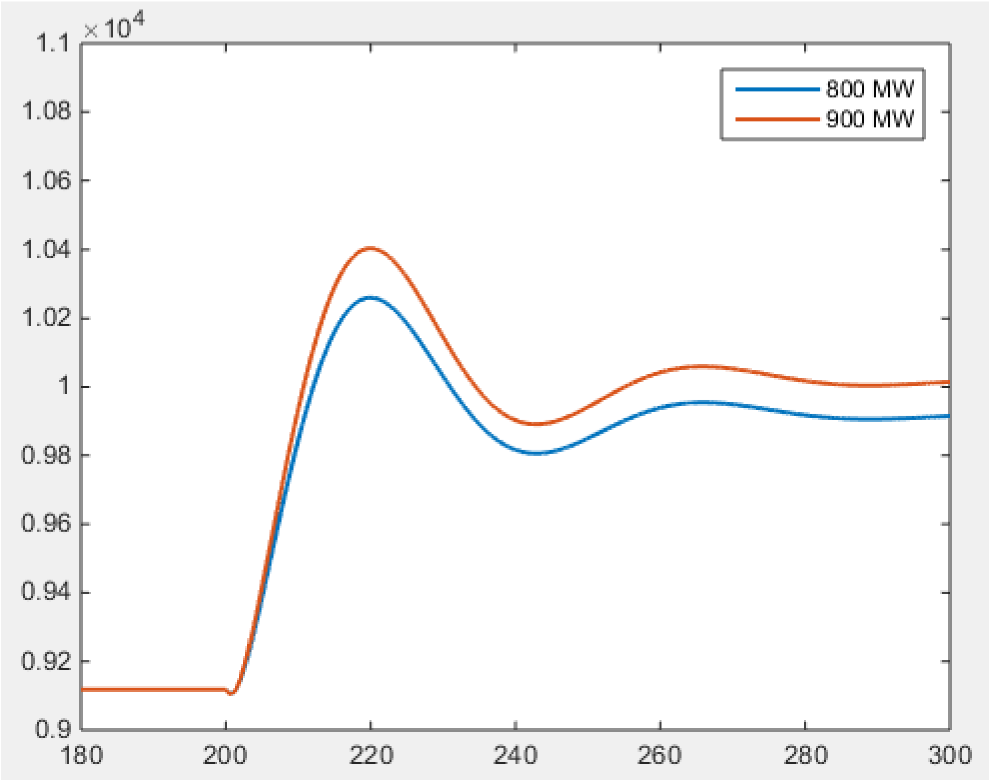

Figure 37: The power supply after losing 800 MW or 900 MW power production.

Figure 38 shows the frequency response for the same scenario, but with different proportional gain. The block diagram for the governor was presented in above in chapter 3 about the model. Figure 39 shows the effect of the time constant and the proportional gain on the power response. The proportional gain increases the response to a fault efficiently. By lowering the time constant, the power response improves, but is not satisfactory before the time constant is unreasonably low. Estimates tell that the time constant should be between 6-10 seconds [22]. In the reference scenario, the time constant is 5 seconds. To reduce the time constant has an effect, but not until it is unreasonably low compared to the given value and the reference scenario.

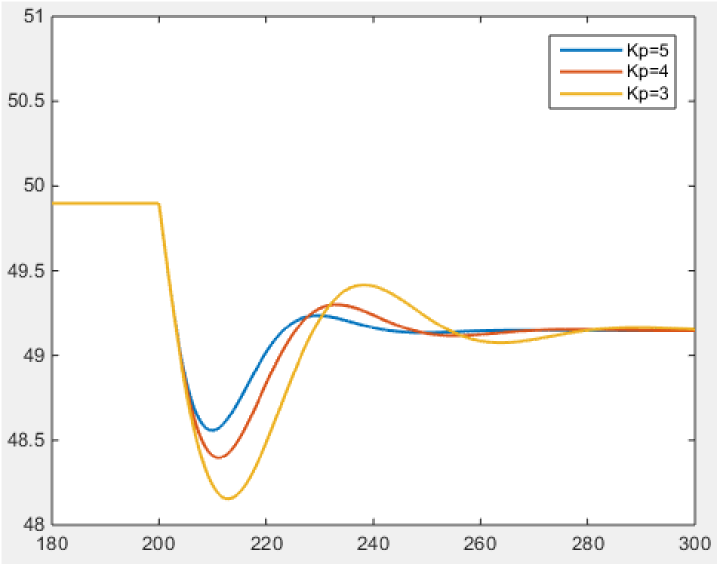

Figure 38: The effect of changing the proportional gain.

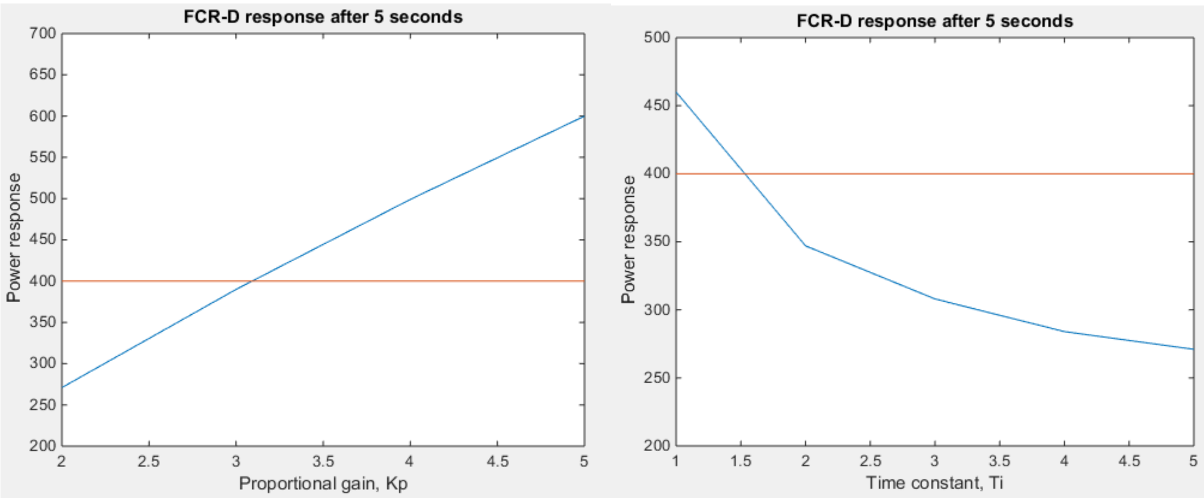

Figure 39: FCR-D response versus the proportional gain and versus the time constant respectively to the left and to the right. The red limit marks the required 50 % response after 5 seconds. Both cases are shown when the system has lost 800 MW of production.

For the reference scenario, the proportional gain is 2. When the proportional gain is increased to 3, the governor is able to provide 390 MW extra production within 5 seconds. This is close to the required response, which is 400 MW. However, with an increased proportional gain, the system can withstand a larger dimensioning incident without exceeding the frequency limits. With 3,1 as the gain value, the frequency does not drop to 49 Hz before the fault is 1000 MW. The power supply after five seconds is 500 and therefore, the increased fault does not require a higher proportional gain. The size of the failure does not influence the percentage delivered after five seconds, as long as the necessary spinning reserves are available.

Figure 40 shows the result graphically. Above the red line, the inertia is the problem and below it, the dynamic FCR-D that requires 50 % response after 5 seconds of the lost power limits the fault the system can withstand. All the fault decided drops to 49,0 Hz. Figure 41 shows the value for the faults for the different values of K_p.

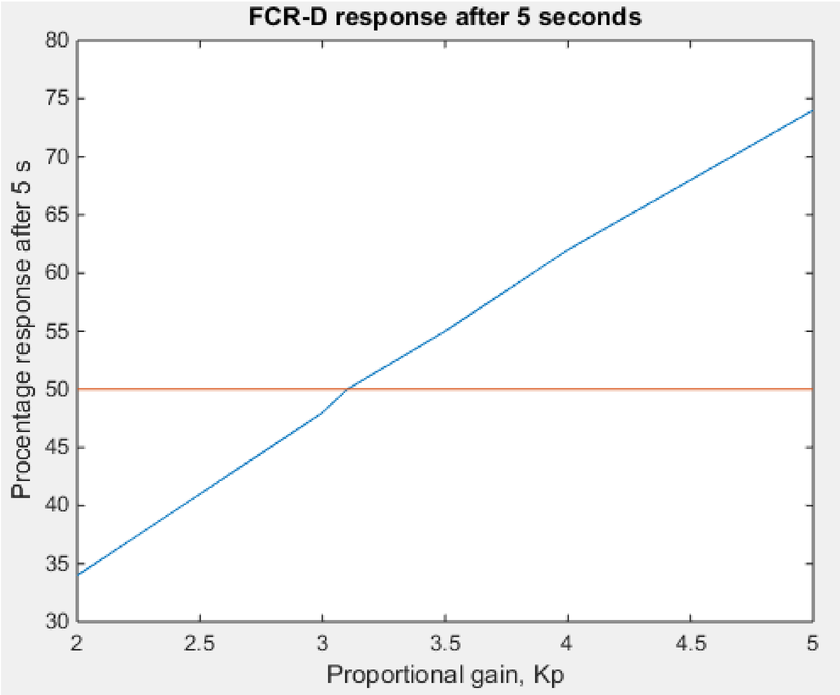

Figure 40: This graph shows at what proportional gain the inertia is the limiting factor versus when the FCR-D is the limiting factor. For all the operating conditions along the blue line, the lowest frequency is 49 Hz in the transient period. The faults are different in size, but the graph shows that below the red line the FCR-D is the limiting factor. Over the red line, the inertia is the limiting factor.

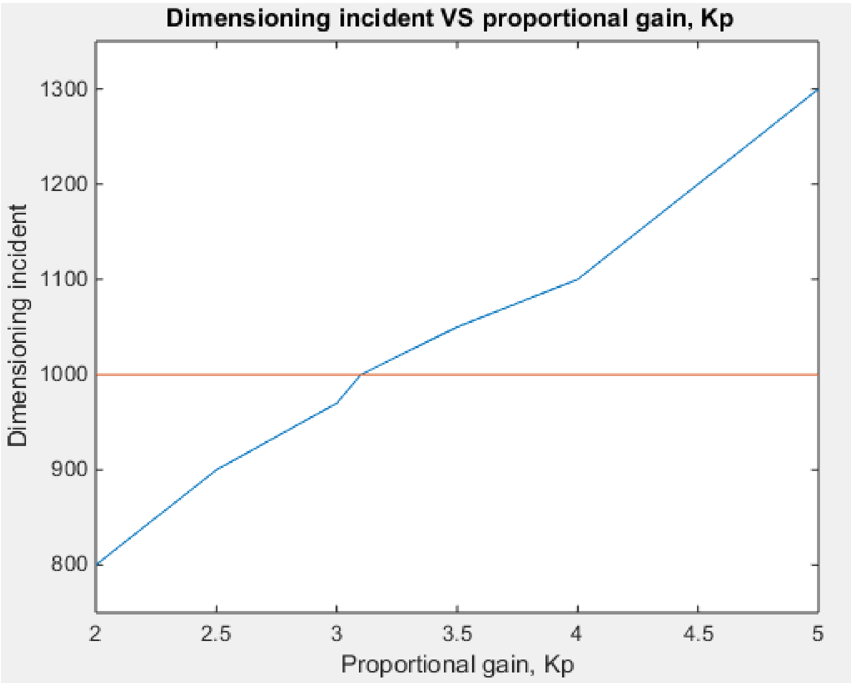

Figure 41: The blue line shows the possible dimensioning incident based on the value of the proportional gain and that the system drops to 49,0 Hz. Below the red line the dynamic FCR-D requirements, activation of 50 percent of the lost power, is not fulfilled. Above the red line, sufficient power is provided. The limiting factor above the red line in this case is the system inertia.

The full activation of the FCR-D reserves should happen within 30 seconds after the incident. A second requirement is that the steady state frequency after the incident should never be below 49,5 Hz. Figure 42 shows the frequency response and the power response for two of the incidents that where operates within the required limits for frequency response and power response after a disturbance. For the red alternative the frequency stabilizes at 49,52 Hz. As the left graph shows, the power supply is stable 30 seconds after the incident. The frequency for the blue alternative stabilizes at 49,62 Hz. However, the power supply is not stable after 30 second, but the necessary amount is provided within 30 seconds.

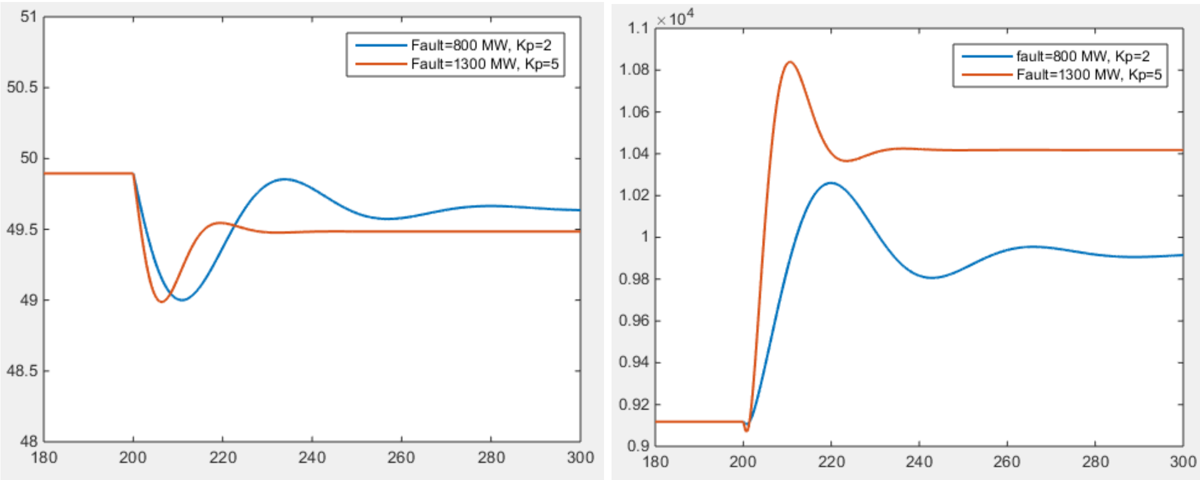

Figure 42: The graph to the left shows the frequency response for the highest and the lowest dimensioning incident for scenario 2B. The graph to the right shows the power response of hydropower.

5.3.1 Alternative 2C – Production portfolios vs possible dimensioning incident.

In alternative 2A, the inertia was increased to show how the system could withstand an increasing dimensioning incident in relation to that. Alternative 2B presented the relation between maximum frequency deviation, FCR-D, and the possible outage the system can withstand. In alternative 2C, the relation between the production portfolio for 22038 MW and the dimensioning incident the system can handle is demonstrated. Figure 43 illustrates that the fastness of FCR-D and maximum frequency deviation have the opposite tendency. An increased amount of kinetic energy both delays the time for the frequency to reach the lowest value and increases the recovery time. Increased inertia also reduced the frequency deviation. However, it is important

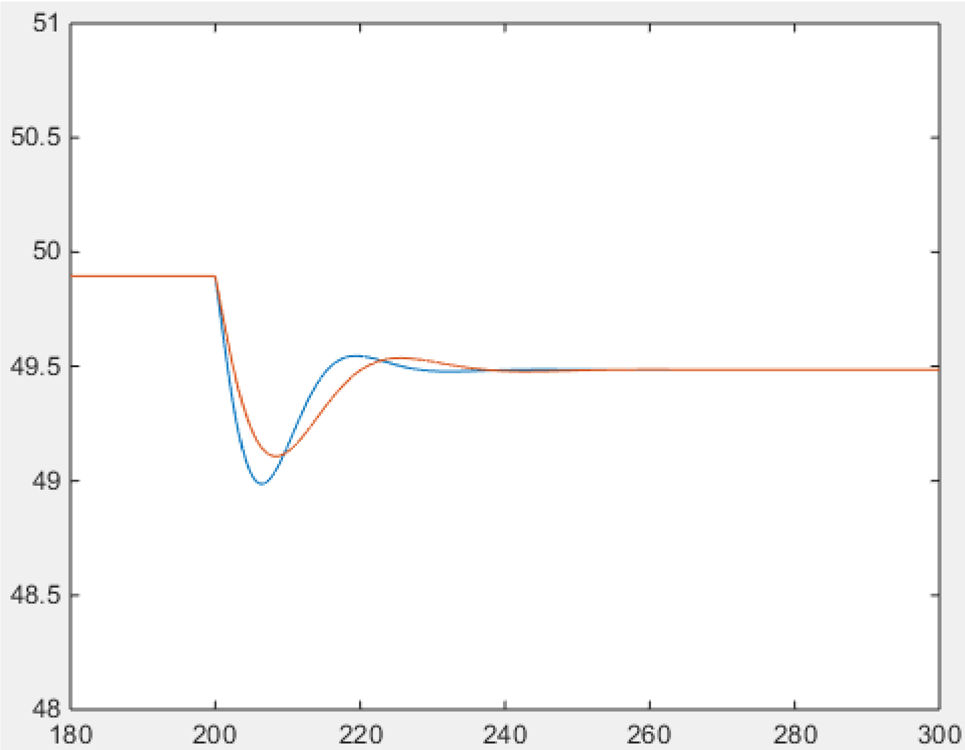

Figure 43: These frequency responses are for the same incident, but with different amounts of inertia. The red line has the highest amount of inertia. The graph shows how inertia improves the transient response by increasing the lowest frequency, but it slows down the system response. Slowing the system can destroy the fastness of the FCR-D response.

The starting point is the operating conditions that were the limit between inertia and FCR-D being the limiting factor. Figure 41 showed this in scenario B. At this point the proportional gain was 3,1 and the dimensioning incident was 1000 MW. The droop is lowered 8 percent to avoid too low stabilizing frequencies.

The first step in alternative C is to test how the generation portfolio affects the frequency response and the maximum frequency deviation. This scenario explores the impact that conventional sources have on the FCR-D response and the frequency response. New renewable energy sources will be studied in Scenario 3. All the tests that are performed in this part generate 22038 MW electrical power in total. Table 9 shows different compositions of the total power for the different alternatives.

The system inertia changes since the synchronously connected power changes due to changes in the production portfolio.

For each production portfolio, the loss of production leads to frequency about 49,0 Hz in the transient period is given as that portfolios dimensioning incident.

Table 9: Different portfolios for low production.

Production portofolios[MW]						
% hydro	Nuclear	Hydro	Thermal	Wind	Total	Kinetic energy [MWs]
50,4	9127	11118	854	939	22038	145128
41,4	10127	9118	1854	939	22038	142089
36,3	11000	8000	2100	938	22038	140397
31,8	12000	7000	2100	939	22039	138877
22,7	14000	5000	2100	939	22039	135838

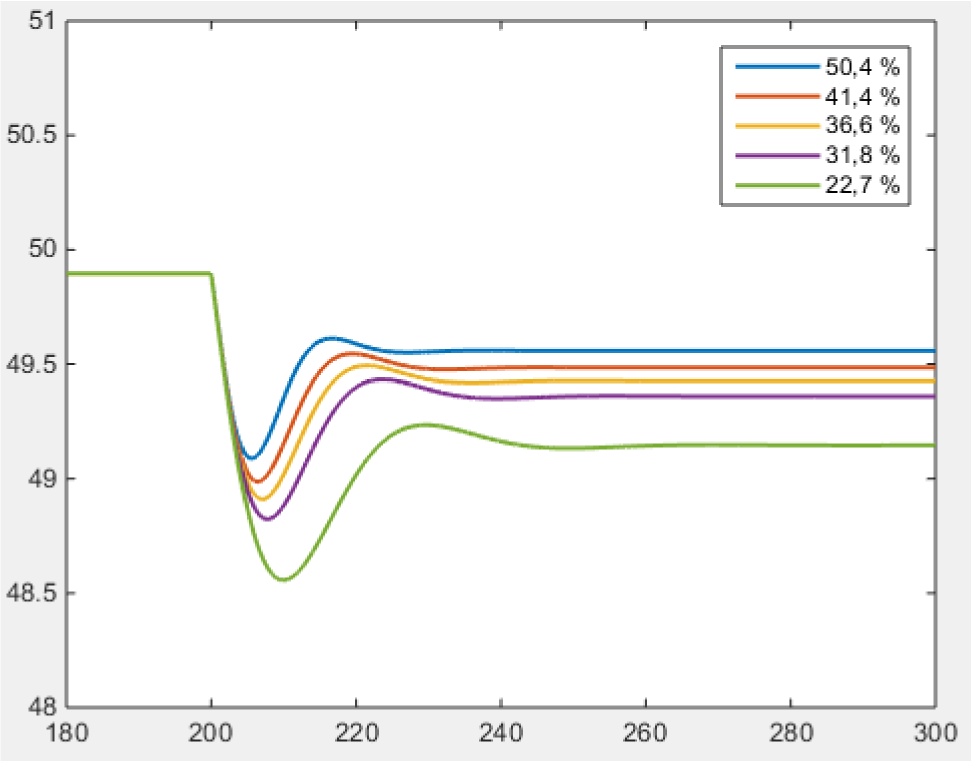

Figure 44: The graph shows the frequency responses for the same production amount, but with different portfolios. The number indicates what percentage the hydropower constitutes of the total power supply. The incident is 1000 MW.

It was impossible for the three alternatives with the lowest share of hydropower to deliver enough FCR-D. The graph in Figure 45 shows the maximum fault the system can handle if the frequency should not drop below 49,0 Hz.

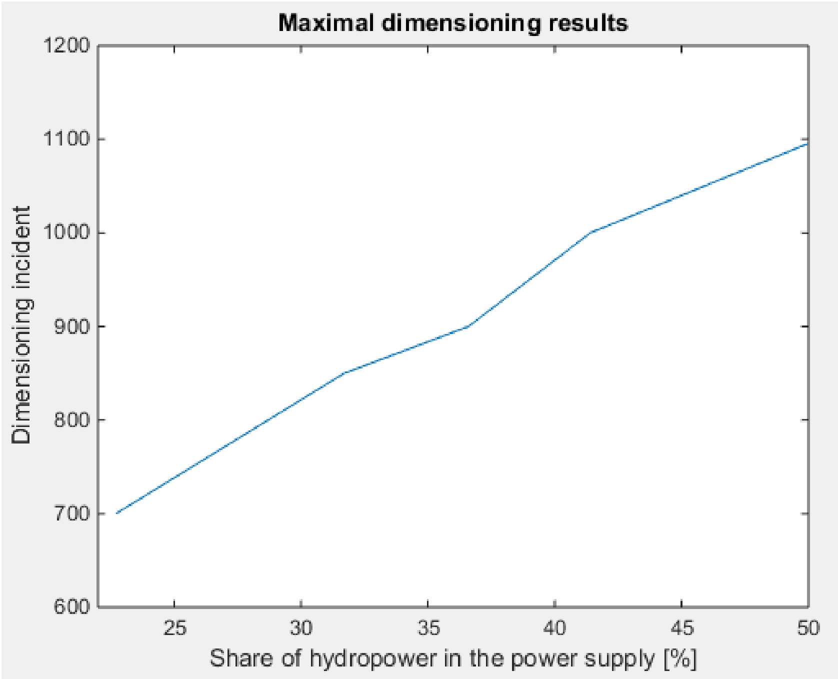

Figure 45: The limits for dimensioning incident versus share of hydropower in the power supply. However, only the inertia is satisfactory with low share of hydropower. With a portfolio which contains less than 41,4 percent hydropower, the FCR-D is not satisfactory.

By increasing the gain, the FCR is still not satisfactory with any of the three last composition of power supply. It is required a frequency bias of 3000 MW/Hz. This can be changed by lowering the droop setting. This is not tested, and will not be analysed but registered.

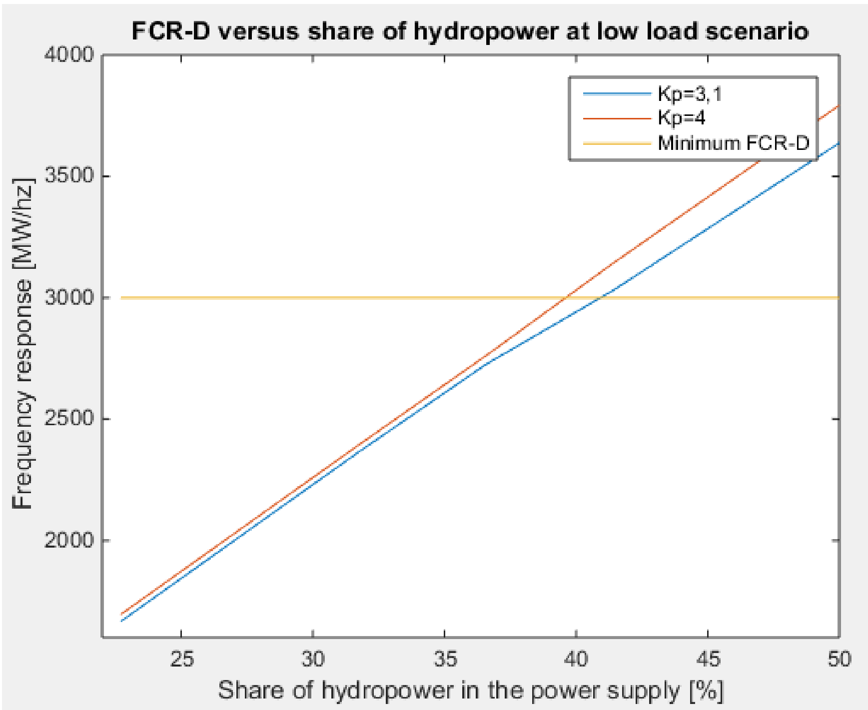

Figure 46: The relation between share of hydropower and the level of frequency bias. The lines shows the operating point where an incident make the frequency drop to 49,0 Hz.

Figure 46 illustrate that even though the inertia is satisfactory, the FCR-D does not necessarily fulfil the requirements. If the maximum frequency deviation meets the requirements, this does not mean the FCR-D is satisfactory. The line marks the demand for minimum FCR-D available. Above the line are the alternatives with at least 40 percent hydropower.

Table 10 and Table 11 show how the operating conditions tested above met the requirements for FCR-D and the transient response after disturbance. All the scenarios have the same total production. The scenarios listed in these tables are the ones from Table 9. *R* in the model is the requirement for the frequency bias.

Table 10: The table shows if the scenarios listed in the left columns meet the requirements for frequency response after an outage of a production unit. The proportional gain is 3,1. The green colour means the requirements are fulfilled, the yellow means it is the limiting factor and the red means it is not fulfilled.

Results simulations, Kp=3.1						
% hydro	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
50,4	1100					
41,4	1000					
36,3	900					
31,8	850					
22,7	700					

Table 11: The table shows if the scenarios listed in the left columns meet the requirements for frequency response after an outage of a production unit. The proportional gain is 4. The green colour means the demand is fulfilled, the yellow means it is the limiting factor and the red means it is not fulfilled.

Results simulations, Kp=4						
% hydro	**DI[MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
50,4	1300					
41,4	1100					
36,3	1050					
31,8	980					
22,7	780					

The response after five seconds does not improve by changing the size of the unit that is tripping. The system model is close to linear and therefore this effect cannot be improved by lowering loss of production. The percentage increase in production remains the same.

In the alternative with 41,4 percent hydropower, both the inertia and the FCR-D limits the size of the possible dimensioning incident the system can handle. When the proportional gain is 3,1, the frequency bias is 3030 MW/Hz, the lowest frequency is 49,0 Hz and after five second the system provides exactly the demanded amount of power, 500 MW. When the proportional gain is four, the limiting factor is the inertia.

For the alternative with 50 percent hydropower, the maximum frequency deviation is limiting the dimensioning incident for both the values of the proportional gain.

5.3.2 Alternative 2D - varying production and load

Alternative 2D tests the relation between production amount and possible dimensioning incident. From Table 9 the production is increased to 30, 35 and 40 GW in this part. Figure 47 shows the relation between the production amount and the dimensioning incident with the proportional gain equal to 3,1. The blue line shows this relation with a share of hydropower equal to 41,3 percent, while the red graph shows the same relation with a share of hydropower equal to 50,4 percent. The graph is linear. For the blue line the possible dimensioning incident is 4,5 percent of the total production. For the red line it is 5 percent.

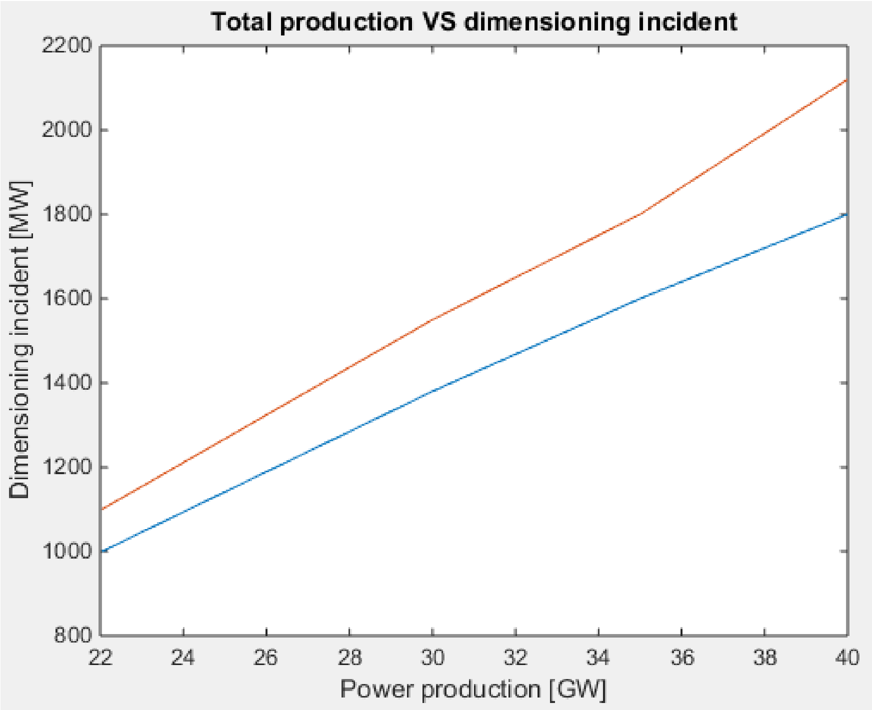

Figure 47: The relation between the size of the total production and the maximum dimensioning incident. The red line is this relation for a production portfolio that contains 50,4 percent hydropower. The blue line is with a percentage of hydropower equal to 41,3 percent. The inertia level increases with the increasing synchronously connected capacity. The formula from the beginning of the scenario is used to calculate this.

The extra power provided after 5 seconds is percentage constant, when the inertia has met its threshold line. In other words, when the hydropower share is 50,4 percent, the system provides 60 % of the original lost production within five seconds. When the hydropower share is 41,3 percent, the system provides exactly 50 percent of the lost power within five seconds.

The graphical frequency response for these four incidents that are tested is the same. The FCR-D is the same regarding delivered power after 50 seconds and after 30 seconds. However, the frequency bias is increasing with the increasing total production. Equation 20 shows the calculation that finds the frequency bias. Δf is the stable frequency change and ΔP is the size of the production loss. Δf is constant, but ΔP is increasing with increased production.

Equation 20

$$R[{}^{MW}/_{Hz}] = \frac{\Delta P}{\Delta f}$$

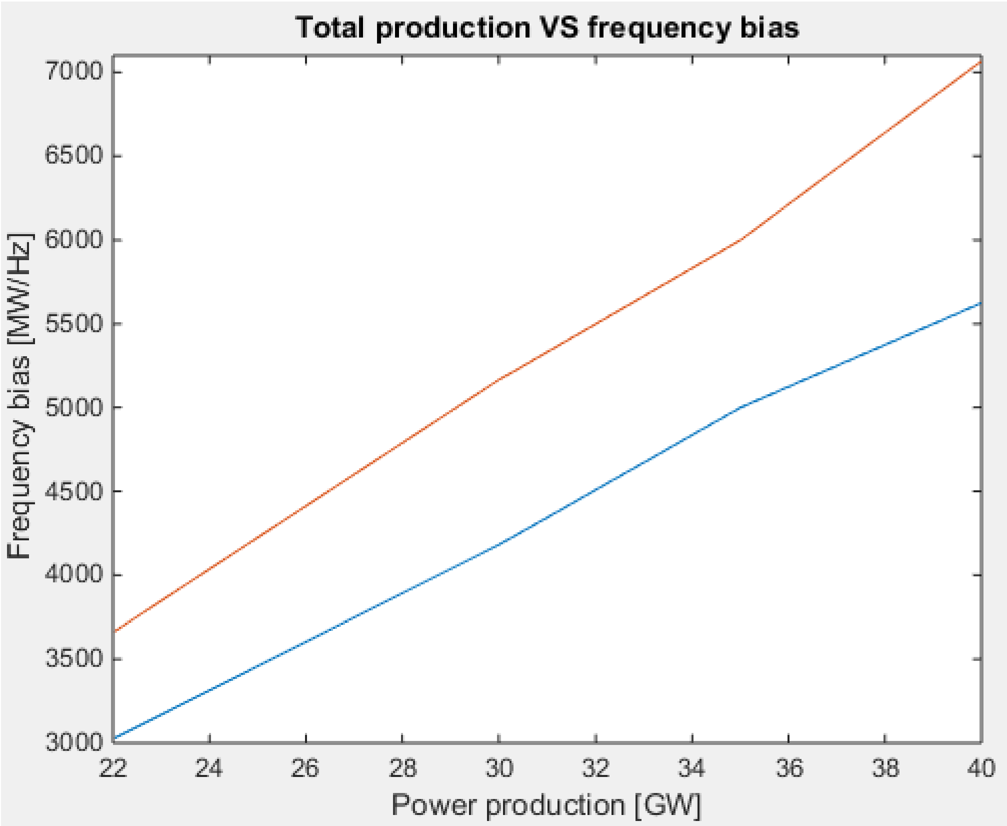

Figure 48: The relation between the frequency bias and the size of the total production. The red line is this relation for a production portfolio that contains 50,4 percent hydropower. The blue line is with a percentage of hydropower equal to 41,3 percent.

5.4 SCENARIO 3 – THE FUTURE SCENARIO

Statnett has developed a worst-case scenario for 2020 which is the basis for the simulations in this chapter. This scenario has a production of 22661 MW, with and without small-scale hydropower. Scenario 3 looks into three alternatives for how the future power supply may look like and how the new and unproven technology can influence the frequency stability.

Alternative 3A looks into how wind power can contribute to synthetic inertia, and how it acts together with hydropower. In this scenario wind power is the only non-conventional power source. Alternative 3B tests how it will affect the system if small-scale hydropower contributes to the system in the same way as thermal and nuclear power. That is a pessimistic assumption, but it was made because this study is a worst-case scenario. Small-scale hydropower has in this alternative replaced conventional hydropower form alternative 3A. Alternative 3C tests how the system can benefit from introducing synthetic inertia and FCR-contribution from the HVDC cables. Import from HVDC originally replaces conventional hydropower form alternative 3A. Later, the HVDC is tried to replace wind power form the original portfolios from alternative 3A

5.4.1 Test of the synthetic inertia from wind power

Before running a scenario including synthetic inertia, the parameters in the synthetic inertia must be tuned and tested. The initial values are shown Table 12. The time constant, the proportional gain, and the start frequency varies in the following figures to show the principal effect of the different parameters.

Table 12: This is recommended value for wind inertia from General Electrics and they are implementet in the model.

Variable Name	PSLF Parameter	Recommended Value
K_{wi}	kwi	10.
db_{wi}	dbwi	0.0025
T_{lpwi}	tlpwi	1.
T_{wowi}	twowi	5.5
url_{wi}	urlwi	0.1
drl_{wi}	drlwi	-1.0
P_{mxwi}	pmxwi	0.1
P_{mnwi}	pmnwi	0.0

Figure 49 shows how the start frequency for the synthetic inertia affects the frequency response. The original value is that it should start at 48,875 or a frequency deviation of 0,125 Hz. This is given in p.u-values in the model as db_{wi}. The interesting results from the figure below is the difference between a starting point at 49,9 Hz or at 49,5 Hz. The 45 Hz value is plotted for comparison. That is practically without synthetic inertia because the frequency never reaches 45 Hz and activates it. This scenario want to highlight how new technology can influence a difficult operating condition. Therefore the most effective initial frequency is used, 49,9 Hz.

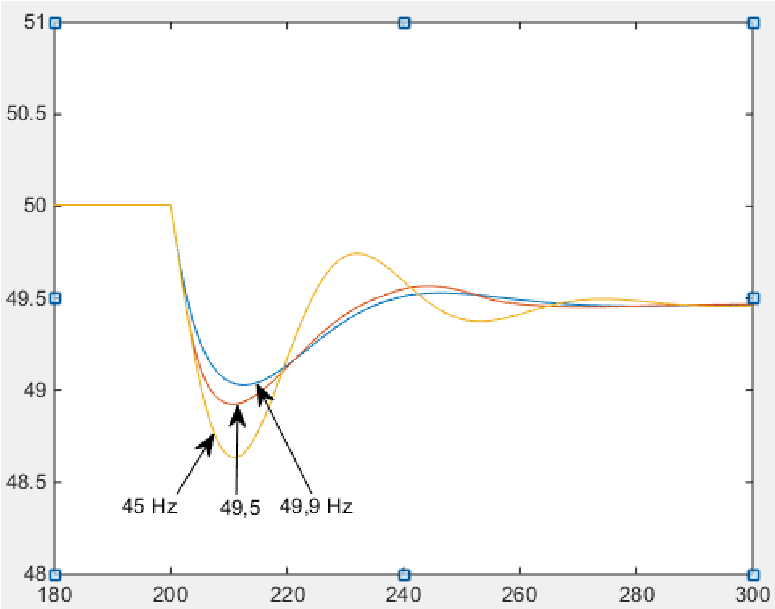

Figure 49: The different graphs have different filters. Activation of the synthetic inertia is at 49,9 Hz for the blue graph, at 49,5 Hz for the red graph and at 45,0 Hz for the yellow graph. The yellow graph is in practice without any synthetic inertia.

The recommended value for the gain K_{wi} is 10. This value is also in pu, but its original unit is MWs/Hz. Figure 50 shows how the different value of the gain effects the frequency response after an incident. This has the same effect as natural inertia regarding the inversely proportional relationship between maximum frequency deviation and the recovery time. If the maximum frequency deviation is reduced, the recovery time for the frequency will increase.

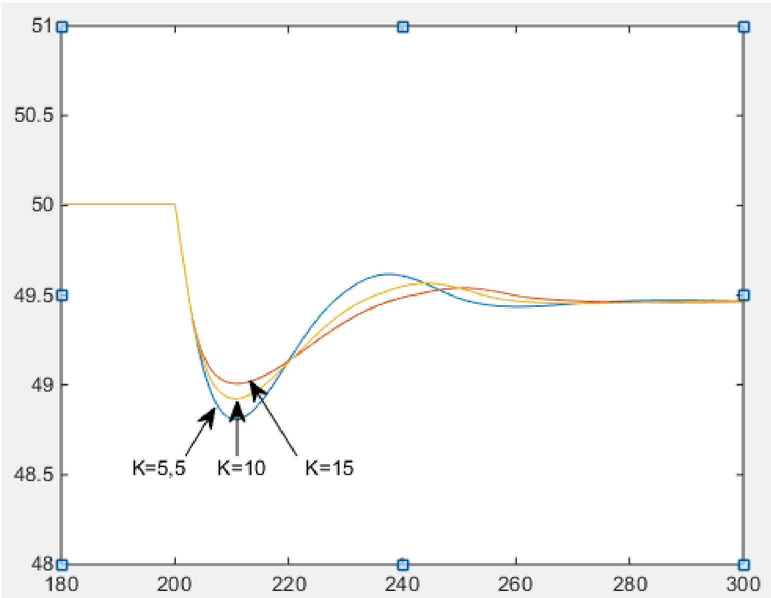

Figure 50: The effect an increasing value of the gain has on the frequency response.

Tw is the time constant in the wash out filter, and its effect is shown in Figure 51. The recommended value is 5,5 and since the effect do not differ much from the changing value of Tw, the recommended value is used.

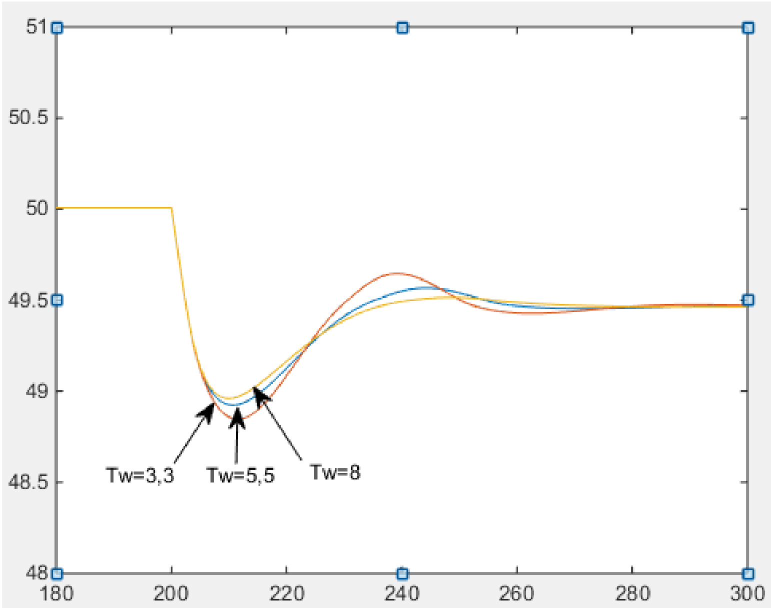

Figure 51: The frequency responses for scenario 3 with varying values of Tw.

Figure 52 shows how the synthetic inertia delivers energy to the system after a fault. In this case there is an installed power of 4693 MW, which means that the 10 percent limit is at 469 MW. The number for production is introduced below. At the peak, the synthetic inertia delivers 434 MW. The frequency drops to 49,08 which makes the large contribution form synthetic inertia acceptable. The graph is also similar to the response that is presented in the theory chapter.

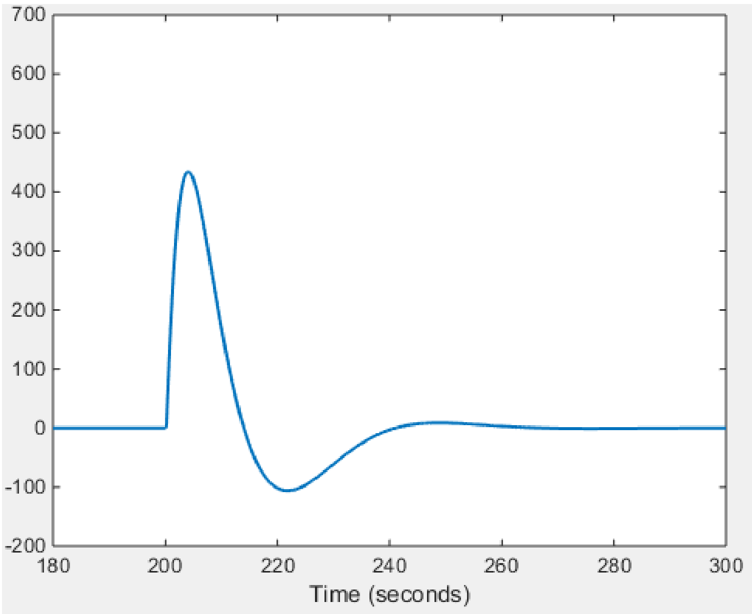

Figure 52: A typical response from the synthetic inertia. Since it is similar to the theory chapter, it is used further on in the analysis.

5.4.2 Alternative 3A – Synthetic inertia, P=22661 MW

Table 13 presents the starting point for this scenario. The tests will look into how synthetic inertia from wind power will affect the frequency response when the power system operates at low load. The proportional gain for the synthetic inertia is the first thing tested. The proportional gain in the governor is 3,1 and the production is 22661 MW for all the tests. Secondly, different portfolios are tested to show the difference between physical and synthetic inertia.

Table 13: Production in the Nordic area in 2020.

Production [MW]				
	Finland	Sweden	Norway	Total
Large scale Hydropower	346	3500	5000	8846
Small scale Hydropower				
Thermal	957	300	701	1958
Nuclear	2564	4600		7164
Wind	1827	2500	366	4693
Total	5694	10900	6067	22661

Figure 53 and Figure 54 show respectively the power response and the frequency response for the different values for the gain in the synthetic inertia. The amount of power that is tripped is not the same in all the cases since all of them have been adjusted to fulfil all the requirements regarding maximum frequency deviation, FCR-D and stable frequency. Table 14 shows the value of the dimensioning incident.

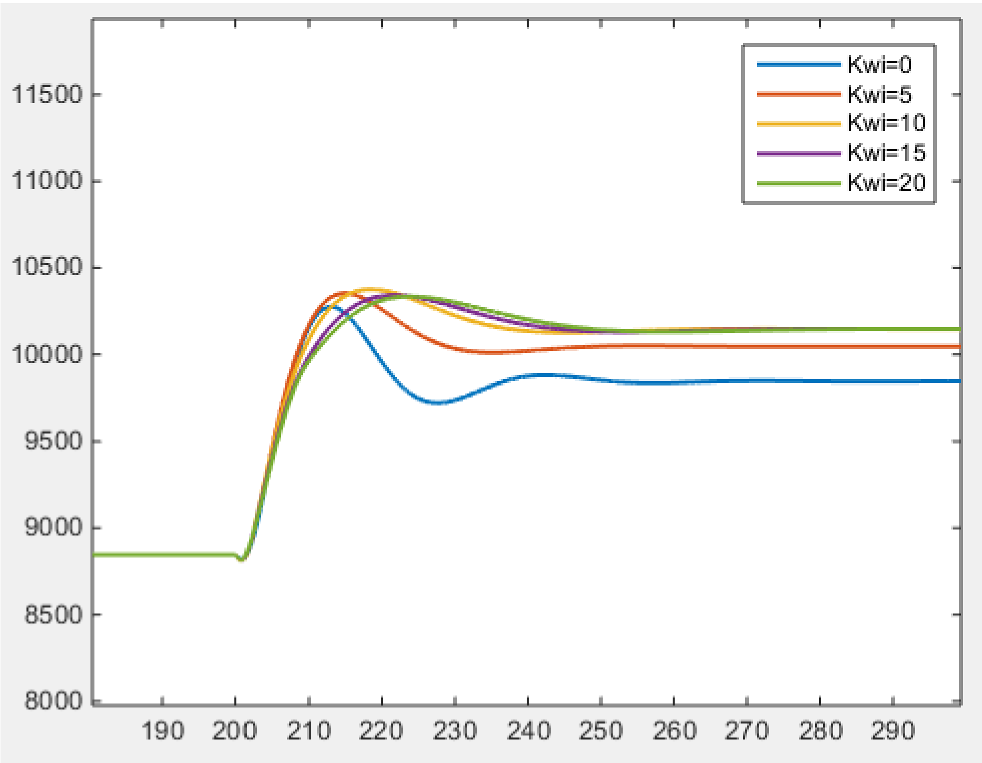

Figure 53: The power response for scenario 3A.

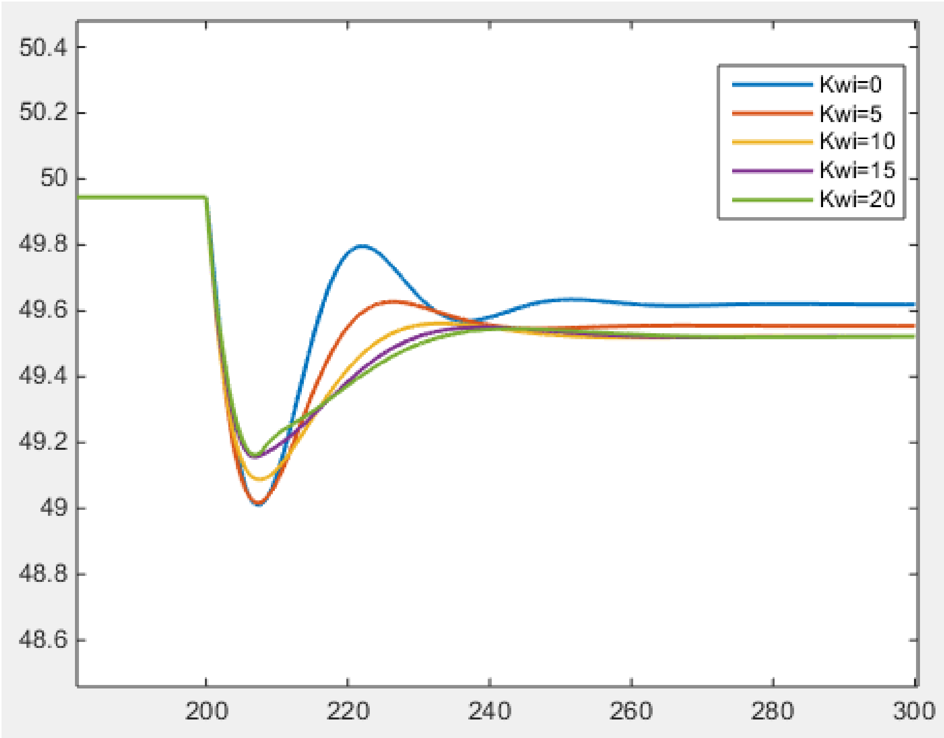

Figure 54: The frequency response for scenario 3A.

Many of the factors are close to their lower threshold value. Table 14 shows the first result for scenario 3A in a table form. The yellow marked area means that this is the limiting factor for the dimensioning incident to be larger. Several of the factors were close to their threshold line.

Table 14: the limiting factors for different values of the gain for the synthetic inertia.

Results simulations, P=22661 MW						
Kwi	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1000					
5	1200					
10	1300					
15	1300					
20	1300					

However, in this analysis all the factors were close to their limits. I addition, this study do not look into the effect the droop can have, and this can easily be adjusted to fulfil the stable frequency demand. Table 15 therefore presents the outcome of the possible dimensioning incident if the inertia is the limiting factor. With these circumstances the stable frequency is too low, but very close to the threshold value that is 49,5 Hz. The permanent droop at 8 percent can be lower, and it is therefore interesting to see what the dimensioning incident can be with the permission to not meet that demand. Figure 55 shows these results graphically.

Table 15: The results for the simulation without taking into consideration that the frequency should stabilize at a higher frequency than 49,5 Hz.

Results simulations, P=22661 MW						
Kwi	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1000					
5	1200					
10	1400		49,47			
15	1450		49,47			
20	1450		49,47			

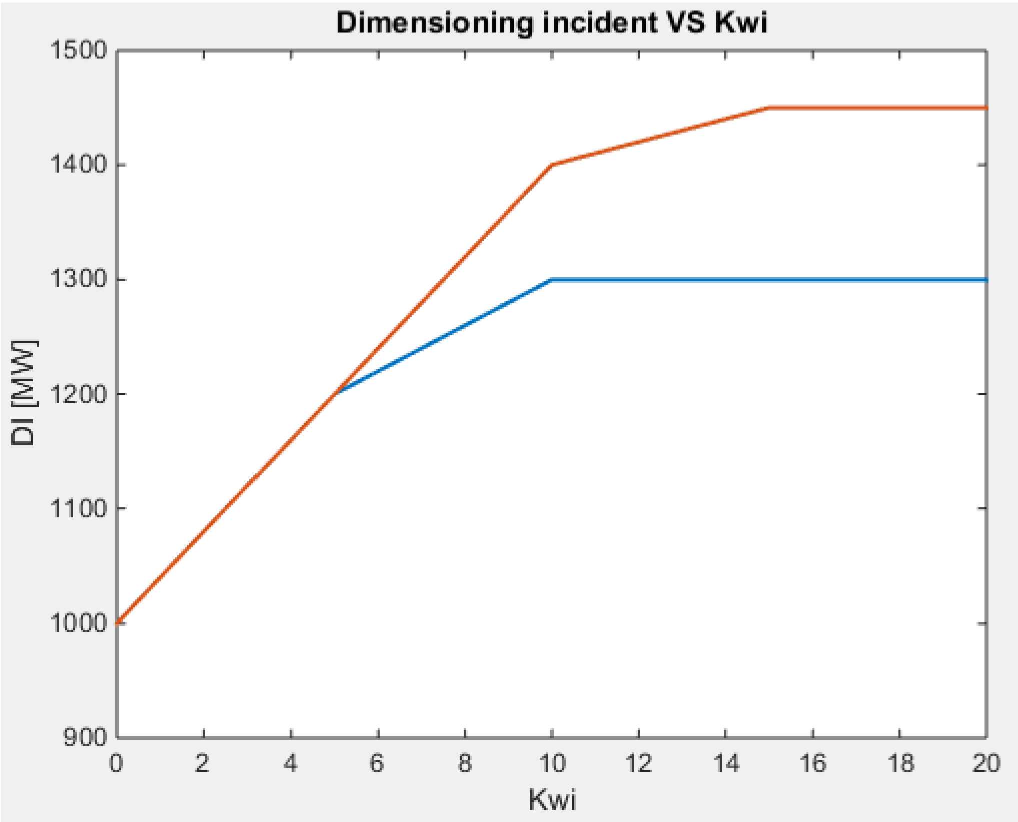

Figure 55: The dimensioning incidents for scenario 3A. The red line shows the results without taking into consideration that the frequency should stabilize at a higher frequency than 49,5 Hz. The blue line is the result when all the demands regarding frequency quality are taken into account.

Synthetic inertia VS real inertia

It is interesting to see how a traditional system reacts to an incident compared with newer technologies. Figure 56 presents the frequency response for an incident where 1300 MW production is lost. The differences between the graphs are the production portfolios. The original amount of wind power, which is 4693 MW, is moved to hydro and thermal for the alternatives with the same names. These three different production portfolios are tested, and wind is tested twice with different K_{wi}.

Table 16: The production portfolios for the comparison between hydropower, thermal power and wind power.

Production [MW]			
Name of scenario	Wind	Hydro	Thermal
Large scale Hydropower	8846	13539	8846
Small scale Hydropower			
Thermal	1958	1958	6651
Nuclear	7164	7164	7164
Wind	4693		
Total	22661	22661	22661

The graph shows that synthetic inertia is better than traditional inertia from nuclear and thermal power plants. Hydropower is still the best, since they provide FCR and inertia. Nuclear and power plants only provide inertia, while wind power only provides extra power during the transient period.

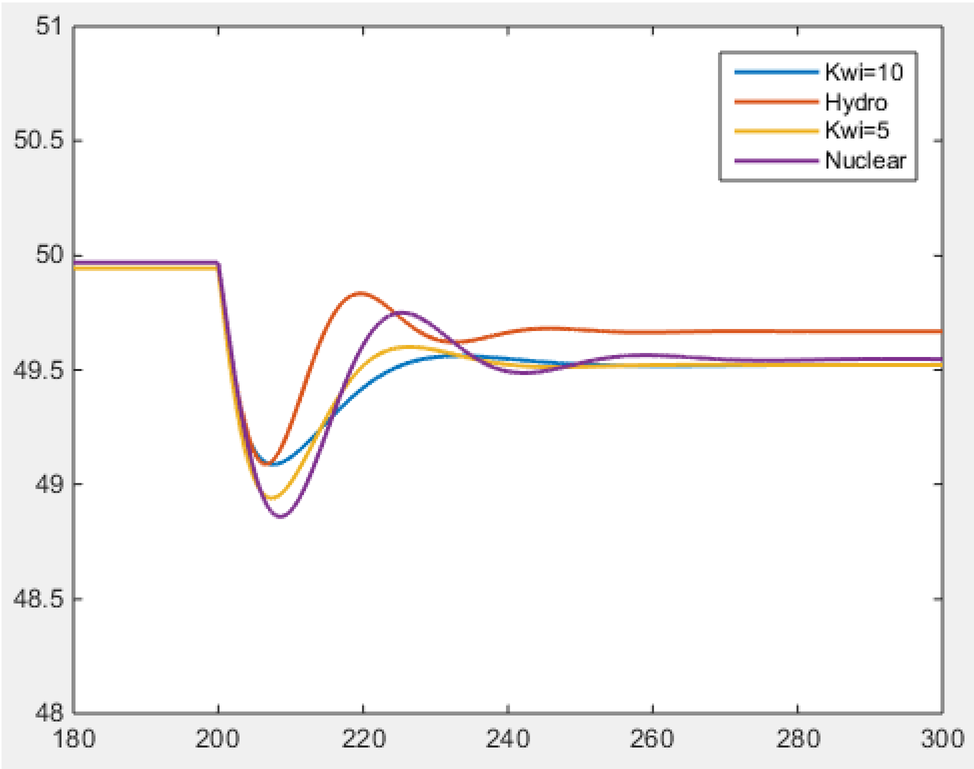

Figure 56: Comparing how different production portfolios reacts to the loss of a 1300 MW production unit.

Synthetic inertia and hydropower

During the recovery time, the wind power will speed up their rotors again by acting as a motor. Figure 57 shows the total power output from synthetic inertia. The relation between the power provided from the hydropower and power from the synthetic inertia has been further studied. 15 seconds after the incident occurred, the synthetic inertia starts consuming power instead of providing. At this point, the power output from the hydropower is at its peak value and delivers 1511 MW extra power. That is 200 MW more than needed. The maximum power consumed by the synthetic inertia generators is 105 MW after 22 seconds. At this point, the surplus energy from the hydropower is 200 MW. These production units therefore complement each other.

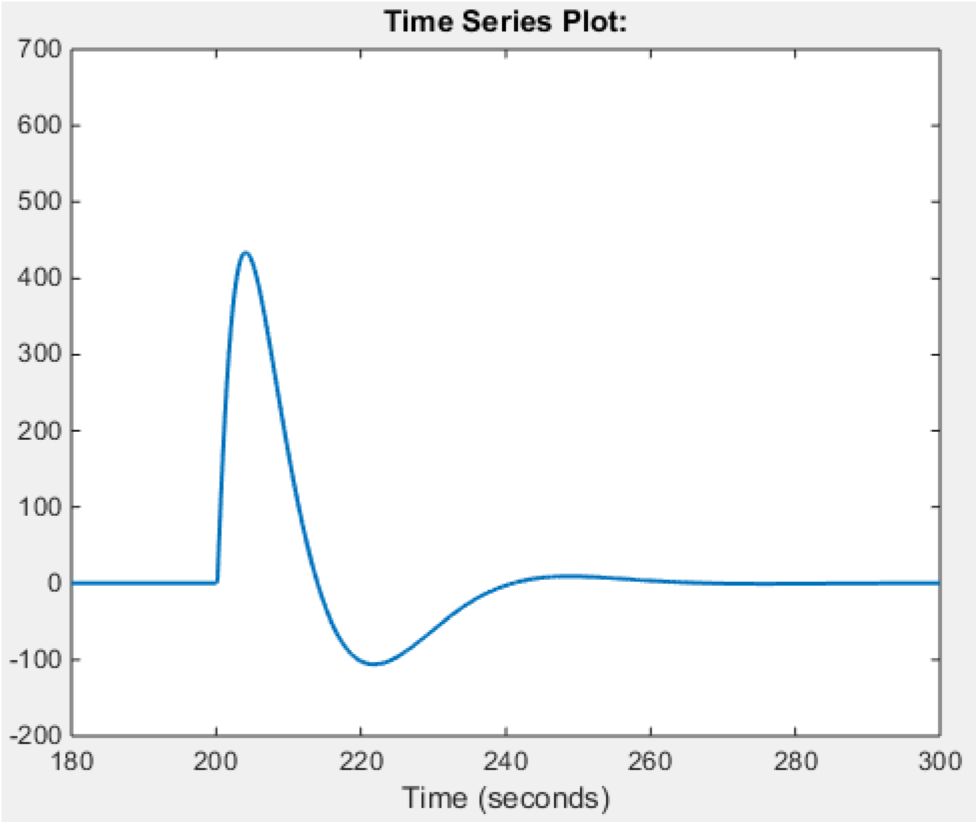

Figure 57: The response from the synthetic inertia during the disturbance.

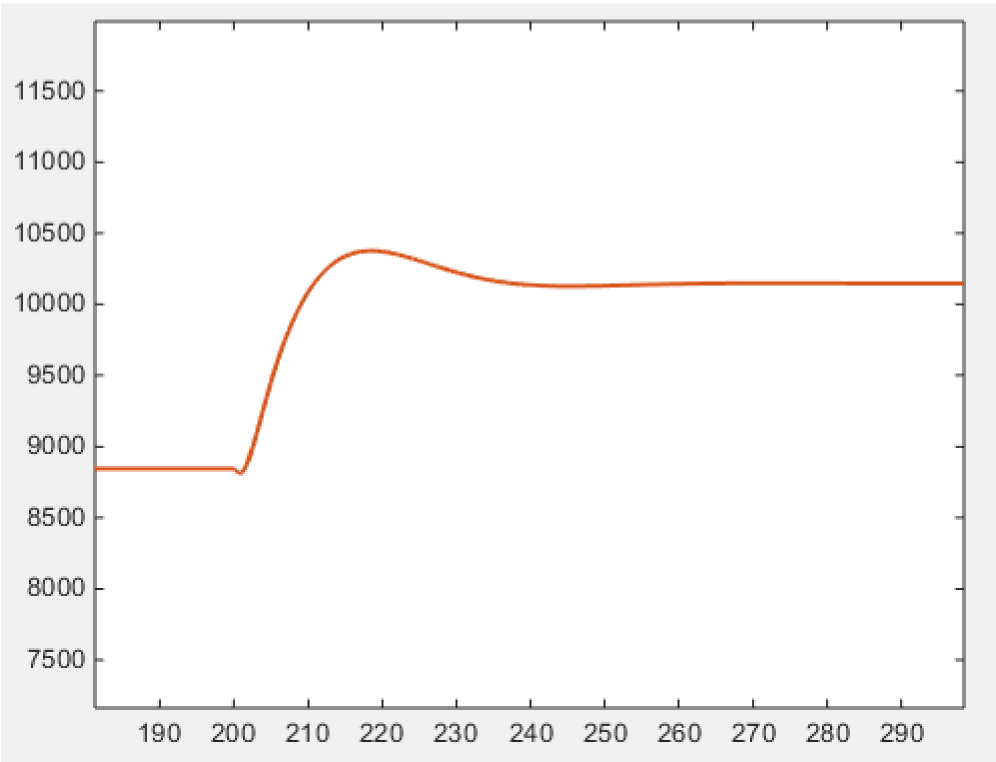

Figure 58: The response from the hydropower during the disturbance.

5.4.3 Alternative 3B – Small scale hydropower

Alternative 3B tests the effect of increasing the share of small-scale hydropower by reducing the share of conventional hydropower. How much small-scale hydropower will contribute to inertia and spinning reserves are still not certain [22]. The starting point in this scenario is the same as in Table 17. This is a part of the worst-case scenario for 2020, presented by Statnett.

The wind is still contributing with synthetic inertia in this case and has a gain of 10. The gain in the hydro governor is constant at 3,1.

The small-scale hydropower constitutes 28 percent of the total hydropower production in the starting point.

Table 17: The starting point for the production portfolio in scenario 4B.

Production[MW]				
	Finland	Sweden	Norway	Total
Large scale Hydropower	346	3500	2500	6346
Small scale Hydropower			2500	2500
Thermal	957	300	701	1958
Nuclear	2564	4600		7164
Wind	1827	2500	366	4693
Total	5694	10900	6067	22661

It is uncertain how small-scale hydropower will contribute during a disturbance. This thesis tests three different methods for modelling small-scale hydropower

I. Small-scale hydropower is modelled as normal hydropower
II. Small-scale hydropower has the same inertia amount as normal hydropower, but do not contribute with spinning reserves and FCR.
III. Small-scale hydropower contributes only with inertia.

The result of these three different methods to interpret how small-scale hydropower contributes with spinning reserves and inertia is as shown Figure 59. This result shows that the inertia is not crucial for the outcome, as alternative II and III practically have the same reaction to the incident.

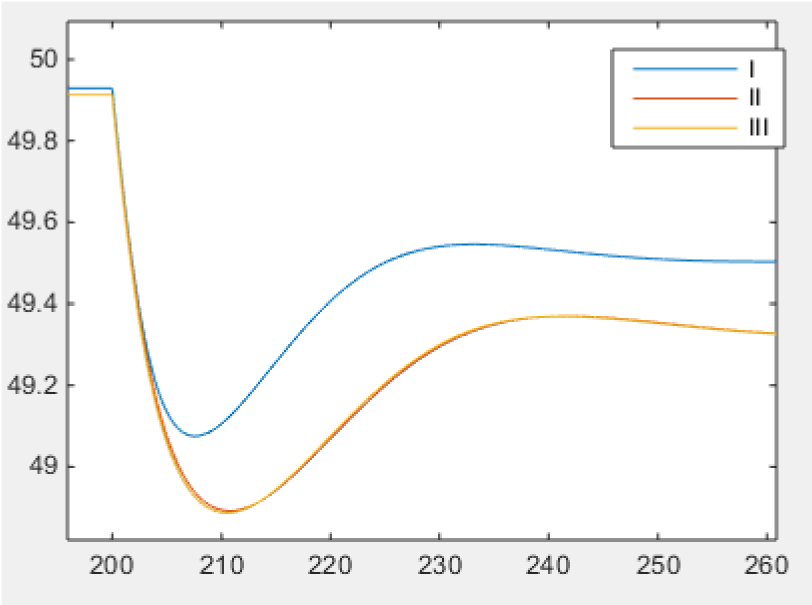

Figure 59: The result of losing a 1300 MW production unit with different interpretation on how small-scale hydropower will contribute with spinning reserves and inertia.

Since alternative I is identical to conventional hydropower, the simulations that follows will continue with alternative III.

Figure 59 shows that the frequency response is not satisfactory. With a starting point that the amount from hydropower in total is 8846 MW and the total production is 22661 MW. The share of small-scale hydropower in the power supply in 2020 is unsure. It is therefore interesting to look at the relation between the share of small-scale hydropower and possible dimensioning incident.

Figure 60, Figure 61 and Table 18 summarize the results from the simulation by varying the share of small-scale hydropower. Only the scenario with no small-scale hydropower had a frequency bias that meets the demands.

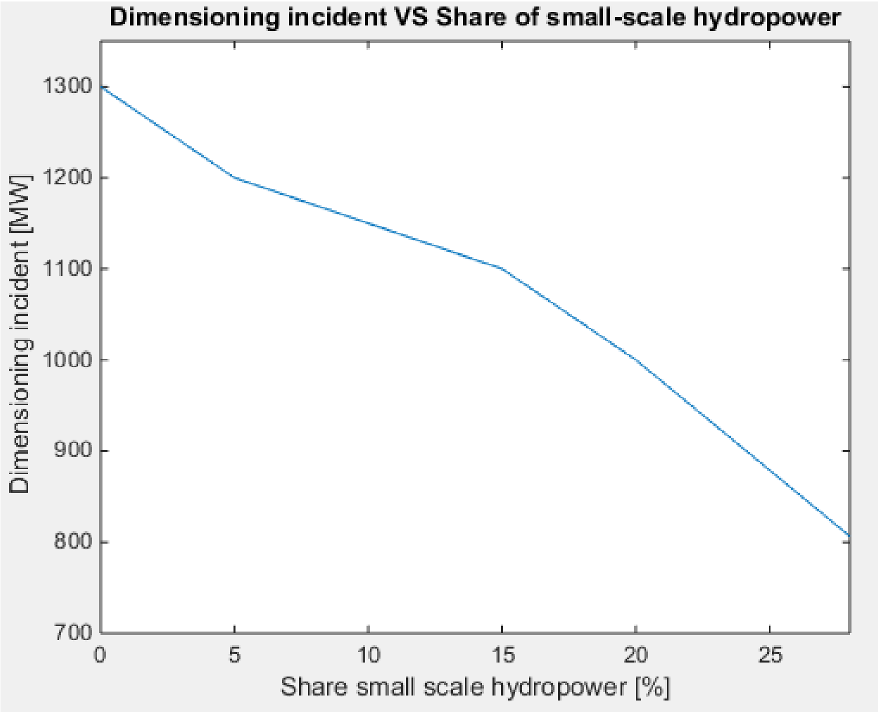

Figure 60: How the dimensioning incident changes with the share of small-scale hydropower. The total production is 22661 MW and the total hydropower production is 8846 MW. The x-axis indicates how large percentage small-scale hydropower constitutes of the total hydropower production.

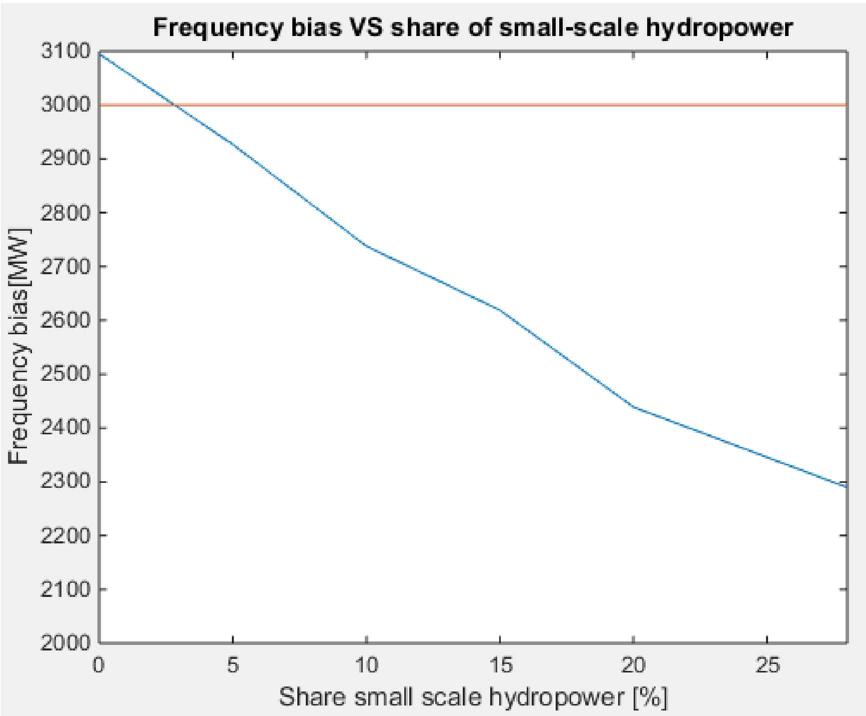

Figure 61: The frequency bias with different shares of small-scale hydropower. With a total hydropower production of 8846 MW and a total production of 22661 MW, all the hydropower must have turbine regulation to meet the requirements for frequency bias. The red line marks the requirement for frequency bias.

Not surprisingly, the FCR-D is a large problem when there is about 6300 MW hydropower production in the system. The stabilizing frequency and the frequency bias could have been increased by changing the droop. But for the two upper scenarios, the frequency almost was reduced to 49,0 Hz during the transient period. The scenarios are presented like this to show how a large reduction of hydropower affects the system in low load. For the scenario with 28,26 percent small-scale hydropower of the total hydropower, the frequency drops to 49,28 Hz.

The transient response for the FCR-D is a problem that can only be better by increasing the proportional gain for the share of conventional hydropower. This was the main limiting factor for this scenario.

It is seen that the effect of the linearity of the model is weaker with synthetic inertia included. In scenario 2, the response after 5 seconds was a constant percent of the lost load. With synthetic inertia, it helps lowering the loss of production to fulfil the 5-second demand.

Table 18: Shows the results of the simulations. The green marking says this factor is within the limit, yellow means this factor is the limits the dimensioning incident. Red means this is below the limit.

Results simulations, P=22661 MW						
% small hydro	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1300					
5	1200					
10	1150					
15	1100					
20	1000					
28,26	800					

Increasing the total production

If the total production is larger, the total percentage of small-scale hydropower can be larger and still meet the demands for frequency quality.

This test is performed by increasing the production and keeping the percentage share of each production type the same as in the starting point of the small-scale hydropower scenario. Production amounts in the test are 30, 35 and 40 GW and the original is 22661 MW.

The two lowest numbers could not reach a frequency bas of 3000 MW/Hz with a share of 28 percent small-scale hydropower of the total hydropower. At 30 GW production the share was 25 percent to meet all the demands, while at 35 GW and 40 GW, the system could handle a share of small-scale hydropower of 28 percent.

ncy never drops below 49,3 Hz.

Table 19 presents the results from the simulations. In this scenario, there are too many factors to present in a graph, but the table shows that the limiting factor is changing when increasing the total production. At 30 GW production, both the frequency bias and the response time is limiting the possible dimensioning incident. At a lower production, the frequency bias is the problem alone. At higher production amounts, the reaction time is the problem. The increased inertia makes the system respond slower to any incident. The inertia is never an issue when the threshold line is 49,0 Hz. At 22661 MW, the frequency drops to 49,07 Hz. At the other scenarios the frequency never drops below 49,3 Hz.

Table 19: The results and the step before the result for scenario 3B – varying production.

Results simulations for 3B - varying production							
% small hydro	**DI [MW]**	**Production [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1300	22661					
25	900	30000					
28	1000	35000					
28	1100	40000					

5.4.4 Test of the synthetic inertia and the emergency power from HVDC

To run a scenario including emergency power and synthetic inertia from HVDC, the parameters must be tuned and tested to get good results.

Figure 62 shows the difference between synthetic inertia from wind power and HVDC-cables. The synthetic inertia from HVDC cables are not well documented among published papers and it is therefore modelled with the same response as synthetic inertia from wind power. The only difference is that synthetic inertia from wind needs recovery energy. At this point, the HVDC just stops the activation of synthetic inertia.

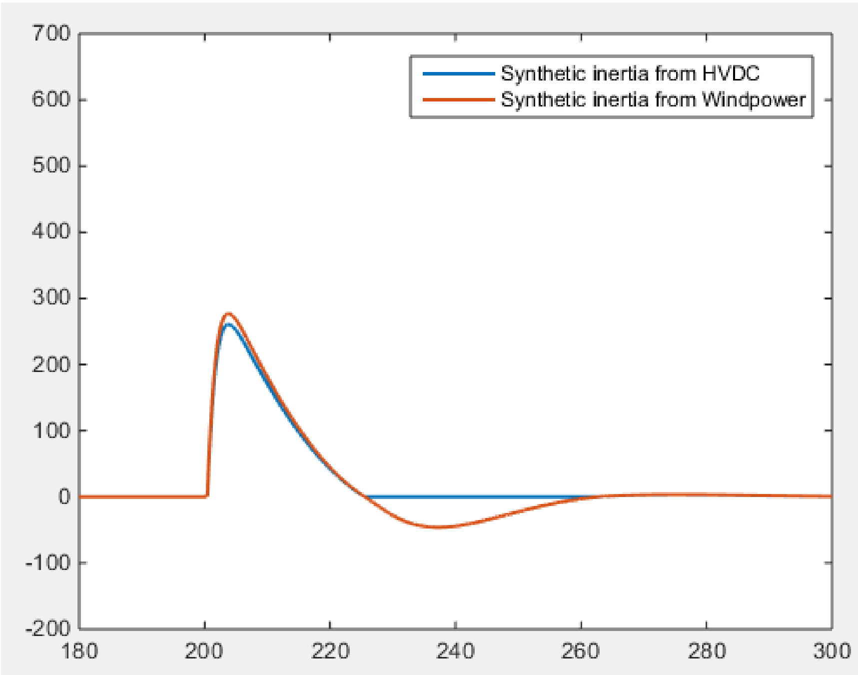

Figure 62: A plot of the synthetic inertia during the disturbance. After the contribution of synthetic inertia, the wind power needs recovery energy. This will withdraw from the grid during the recovery time, and contributes negatively to FCR-D.

A filter, a time constant and a gain decide the emergency power. The emergency power should be proportional to the frequency deviation, but it was necessary to add a filter to damp the largest deviations. Emergency power is not meant as a continuous contribution. In this simulation, it is modelled as that, but the idea is that when the FRR are activated, the emergency power will stop.

The transfer function for the filter with the time delay is like Equation 21 shows. The filter had to be there to damp the oscillation. The tuning of the filter was impossible to show graphical since the system oscillated out of balance. A time delay causes an overshoot, and if the filter is too weak, the system oscillates out of balance. The bode plot for the filter is shown below.

Equation 21

$$H(s) = e^{-\tau s}\frac{1}{1 + 0{,}04\,s}$$

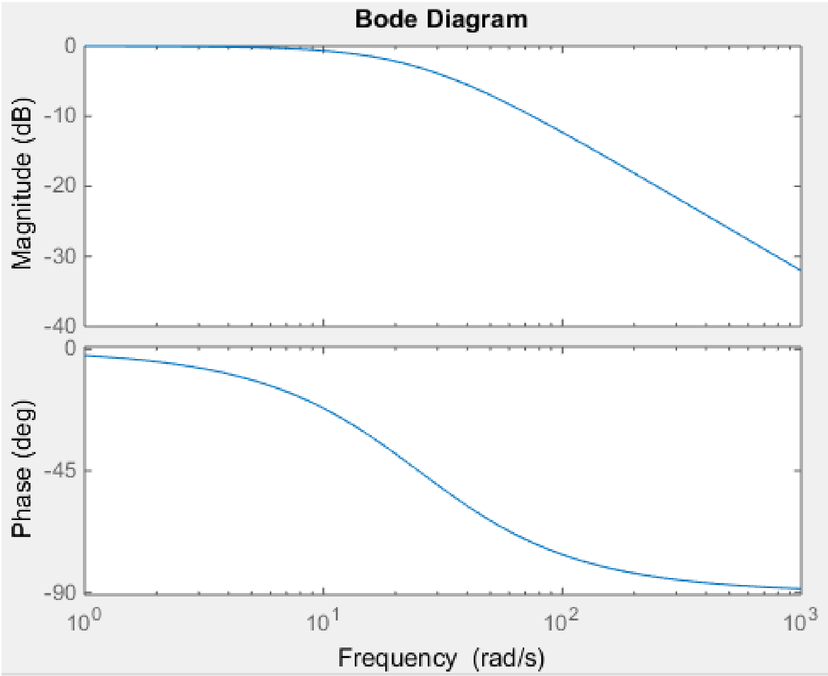

Figure 63: The bode plot for the filter used in the emergency power loop.

The bode plot shows that the proportional gain in the emergency power loop reduces by an increasing frequency deviation.

The base for the emergency power is set to the maximum output, which is 2745 MW in this case. This can be activated within 0,6 Hz deviation from 49,8 Hz to 49,2 Hz. The gain in the emergency power loop should therefore be as calculated below. However, Figure 64 shows that with an increasing gain, the overshoot is higher and with 83 as the gain, the system will oscillate out of balance.

$$K_{HVDC,pu} = \frac{1}{0{,}6/_{50}} = 83{,}33$$

Figure 64 shows the that with a stable frequency deviation of 0,5 Hz, the power supply can be between 100 and 150 MW, depending on the gain chosen. Since this is an illustrative study, the gain is chosen to be five to avoid a large overshoot.

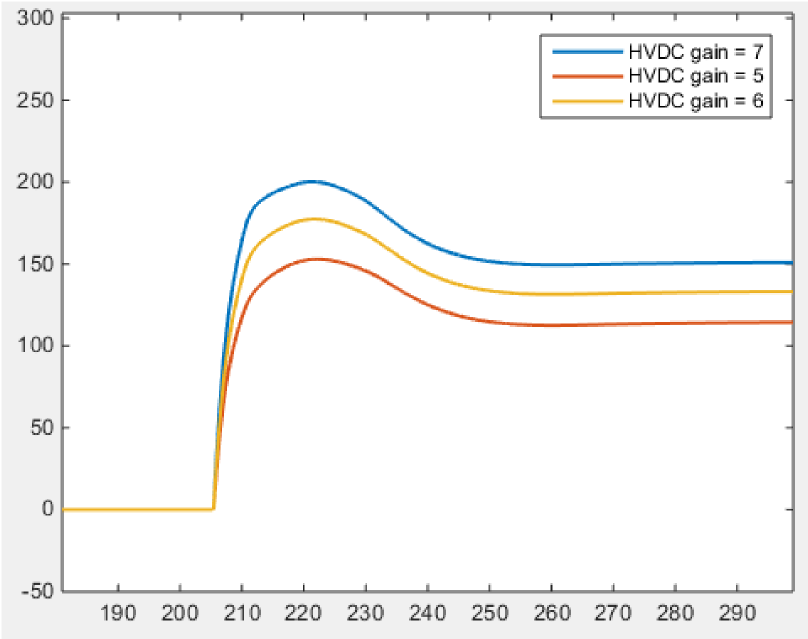

Figure 64: The graphs shows the effect the gain in the emergency power loop has on the power response. The time constant is 5 in this case.

Increasing the time constant delays the reaction and increases the overshoot. The time delay is an assumption and set to 5 seconds.

5.4.5 Alternative C – High import via HVDC-cables

Alternative 3C looks has the same basis as alternative 3A, but explores the effect of replacing some of the conventional power with import via HVDC-cables. The HVDC can contribute with emergency power and synthetic inertia.

This scenario combines many of the effects tested earlier. Several tests can be run with different combinations from critical operating points found earlier, but some operating conditions will be stable. The following parameters are constant:

- The gain of the synthetic inertia is constant at 10.
- The droop in the hydro governor is 8 percent.
- The percentage share of nuclear and thermal production

The following parameters are changing during the tests to explore the effect:

- The total production
- The share of HVDC
- The gain in the emergency power loop
- The contribution from synthetic inertia

The interesting graphs are now increased to four different contributions to the power balance after an incident. The providers are hydropower, synthetic inertia from wind and HVDC and the emergency power from the HVDC.

The starting point and the first frequency response are presented in Table 20. The two scenarios are tested together. The first alternative has the assumption of 85 percent import on the cables connected to Norway. The second reduced the import to allow more active hydropower in the system.

In this scenario, it is assumed that hydropower is the production unit that shuts down production at a low load scenario. This happens when the market and the hydraulic situation makes in more profitable to shut down hydropower at low load and import from the continent. At high load, the prices can go up, and it is profitable for the hydropower plants to sell during these hours instead. This is an assumption, and not necessary the case in 2020.

Table 20: The starting point for the two different amount of HVDC tested in the scenario

Production [MW]		
	HVDC=4420 MW	**HVDC=3000 MW**
Large scale Hydropower	4426	5846
Small scale Hydropower	0	0
Thermal	1958	1958
Nuclear	7164	7164
Wind	4693	4693
HVDC-import	4420	3000
Total	**22661**	**22661**

Figure 65 shows the frequency response for these scenarios. As the figure shows, the maximum frequency deviation is not the main problem, but the recovery time for the frequency is. The emergency power responds after five seconds. At the same time, the first FCR-D response is measured.

After 5 seconds, the 4420 MW-scenario delivers 271 MW extra power. It should be 450 MW to meet the 50 percent demand. The 30 seconds demand is fulfilled, even though it can look like it's not in the frequency plot. This is likely because the high amount of synthetic inertia slows the reaction to the system very much. The nadir occurs 20 seconds after the disturbance. This scenario also stabilizes at 49,3 Hz.

The 3000 Mw-scenario has a slighter better response after 5 seconds, but the main difference is the frequency which stabilizes at 49,5 Hz in this case.

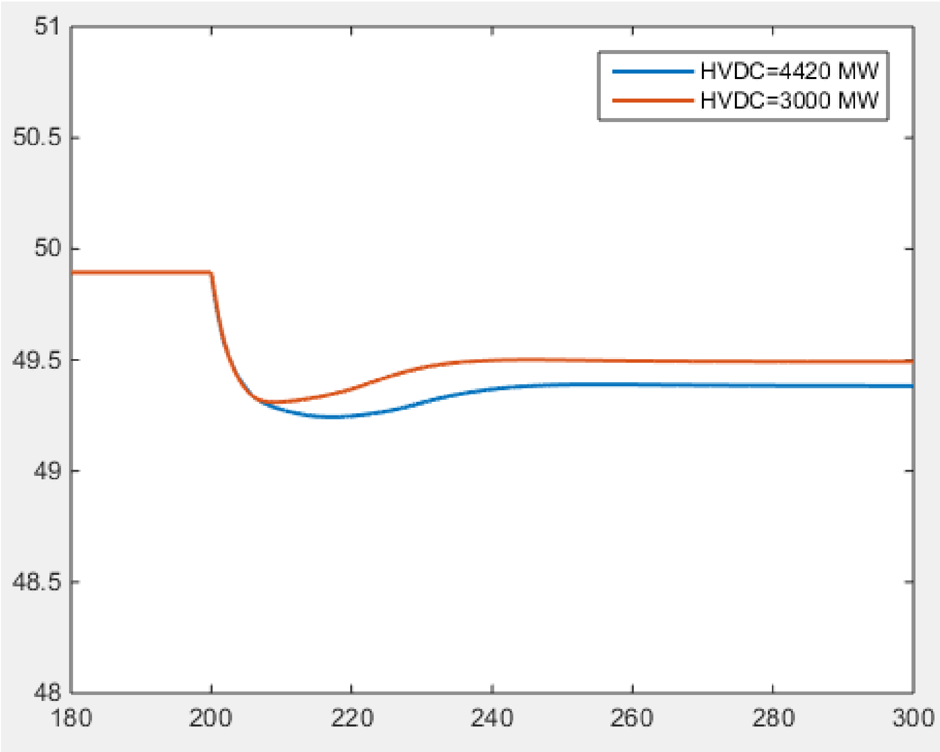

Figure 65: The frequency response after losing 900 MW production.

Since the 4420-scenario does not fulfil the stabilizing demand, the 3000-scenario is investigated further. This could have been regulated by the droop, but it seems unlikely to get a response like the 4420-sceanrio to meet the requirements. Figure 66 shows how combining the different technologies affect the frequency response. All the graphs show an outage of 900 MW. The Emergency power is necessary to reach a stable frequency at 49,5 Hz. With emergency power and synthetic inertia from HVDC, the frequency response is closest to fulfil the demands. 39,9 percent of the lost power is provided within 5 seconds. The frequency bias, which is provided by the hydropower and the emergency power, is 2250 MW/Hz.

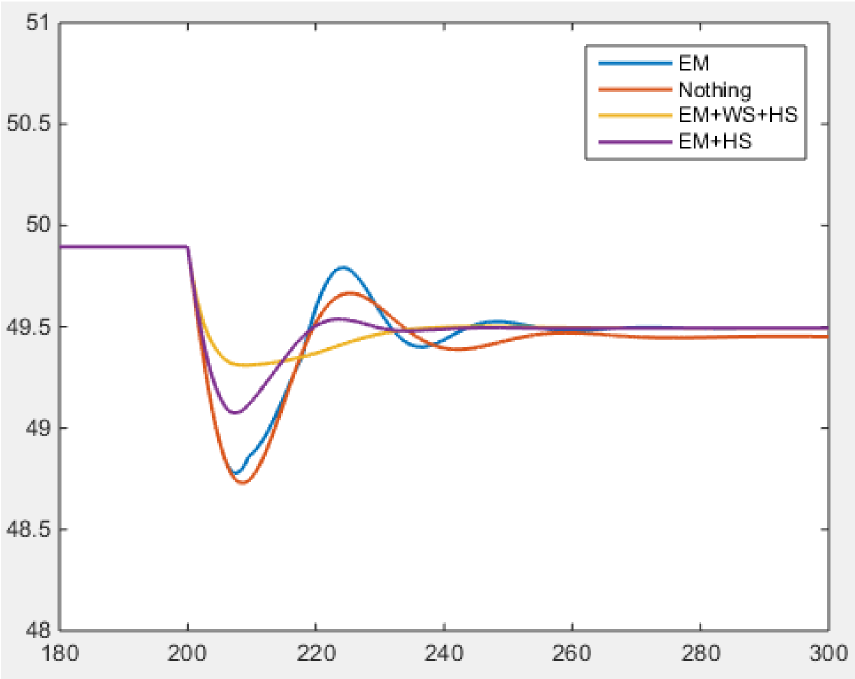

Figure 66: Different ways of combining Synthetic inertia from wind power(WS), synthetic inertia from HVDC(HS) and emergency power from HVDC(EM) in the 3000-scenario.

Since the demands regarding FCR-D never were not fulfilled with the permanent settings, it is tested to increase the gain in the emergency power. However, by increasing the gain from 5 to 20 the stabile power supply increases with about 60 MW. Figure 67 shows the transient oscillation, which is not acceptable. This is not an option to improve the response.

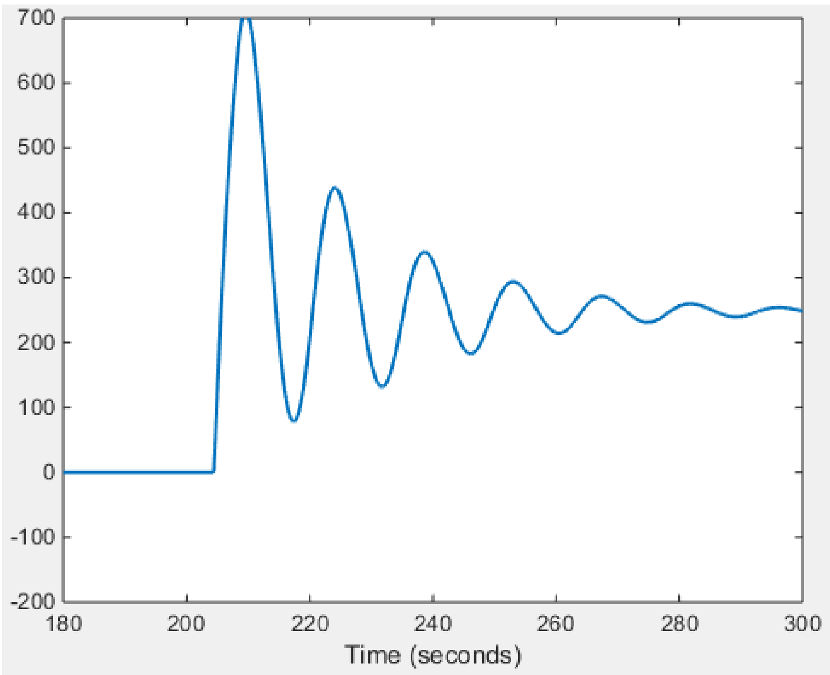

Figure 67: How the emergency power responds to a loss of 900 MW production when the gain is 20.

According to the inertia restriction only, Table 21 shows an overview of the results. In this test the time delay is reduced to 4 seconds to also contribute during the lowest value. Interesting results from this study are result number two and three and the two last results. The difference between the dimensioning incident with and without the emergency power is much larger for the previous results than the later results. Their four graphs are plotted in Figure 68. The figure shows how much the kinetic energy slows down the system. In the slowest system, the emergency power has the time to start providing power before the bottom is reached and will contribute to the power balance.

Table 21: The different possible dimensioning incident if the maximum frequency deviation is the only criteria.

3000 MW import, Total production=22661				
HVDCsynth	**WINDsynth**	**EM**	**Frequency[Hz]**	**DI[MW]**
x		x	49,01	1000
x	x	x	49	1400
x	x		49,02	1200
	x	x	49,01	1100
x			49	750
	x		49,01	1050
		x	49,01	730
			49	700

The table does not consider any demands regarding FCR-D. Figure 68 shows that the FCR-D demands are far from satisfactory for the largest dimensioning incidents.

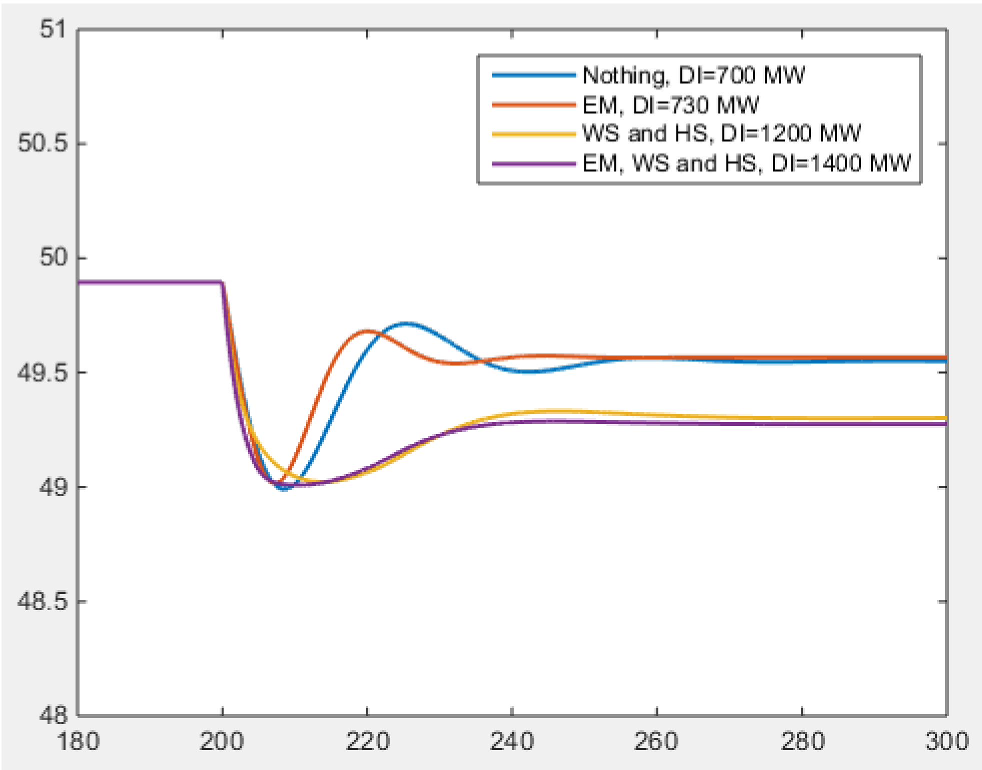

Figure 68: The graphs for four different operating conditions with their maximal incident. The maximum frequency deviation is 0,9 Hz for all the cases.

The reason adding emergency power has a larger effect when synthetic inertia is included, is that when the nadir is reached for the responses with synthetic inertia, the emergency power has a peak value. The response reaches the peak value at the same time. This is shown in Figure 69.

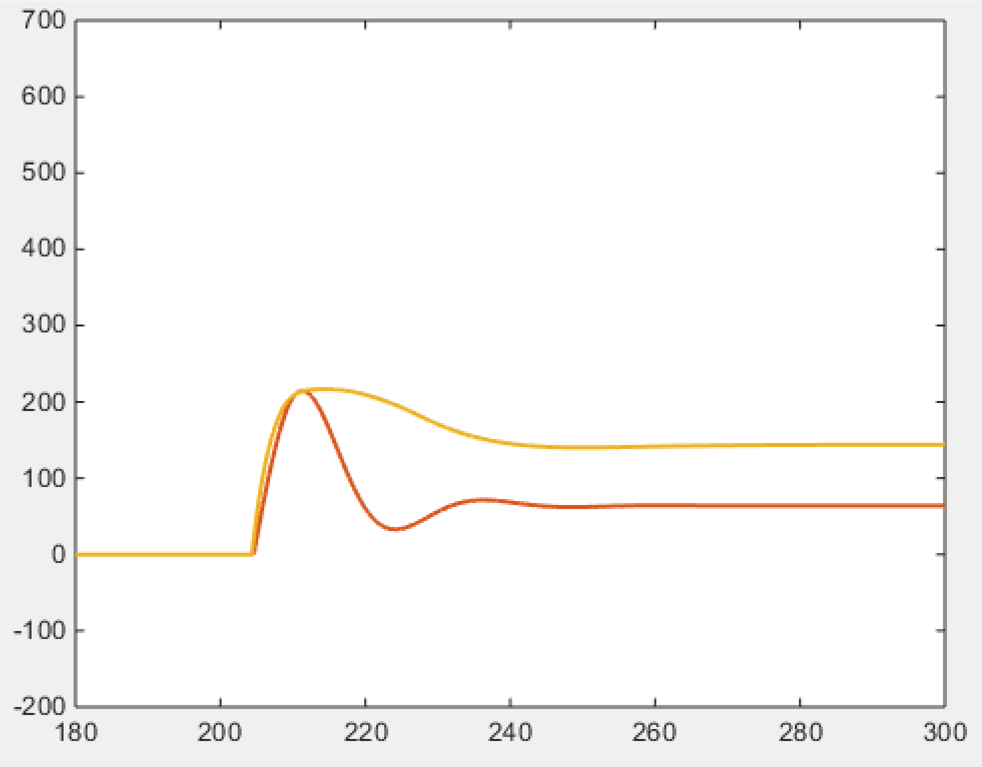

Figure 69: The emergency power response, with and without synthetic inertia. The yellow graph is for an outage of 1400 MW and with synthetic inertia. The red is for an outage for 730 MW and is without synthetic inertia.

HVDC versus wind power

From the previous scenarios, it has been shown that to reduce the hydropower further than the worst-case scenario makes it difficult to satisfy the requirements for FCR-D. Therefore, it is also an interesting scenario to compare different new ways to compensate for lacking natural inertia and FCR-D.

Table 22: Two scenarios were the hydropower is constant at 8846 MW.

Production [MW]		
	Wind	**HVDC**
Large scale Hydropower	8846	8846
Small scale Hydropower	0	0
Thermal	1958	1958
Nuclear	7164	7164
Wind	4693	
HVDC-import		4693
Total	**22661**	**22661**

Figure 70 shows how the system reacts to losing 1400 MW with different techniques to compensate for the loss. It mainly compares how the wind and the HVDC compensate.

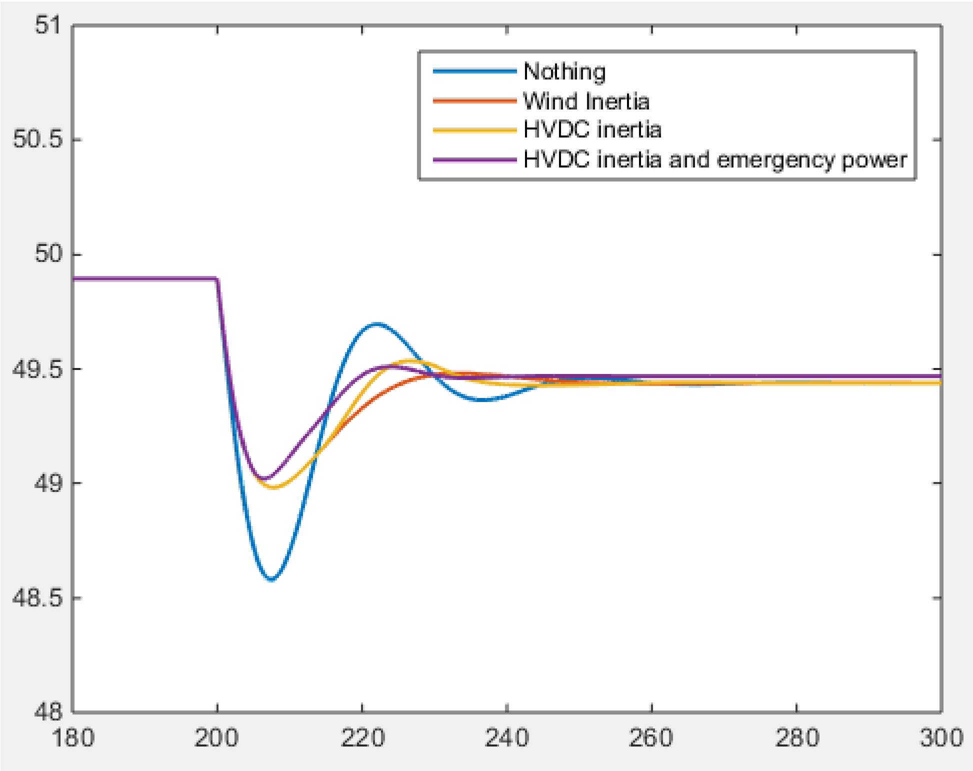

Figure 70: The frequency responses for different tuning of the system after a loss of 1400 MW.

5.5 SENSITIVITY ANALYSIS

Early in this process, a number of assumptions were made. An important choice that has affected the work is the calculation of system inertia constant.

A short sensitivity analysis with a different approach is therefore preformed.

The total amount of kinetic energy was adjusted to be 370 GWs. With the calculation of the assumed system connected capacity, the system inertia constant was 5,47 seconds. This gives the same kinetic energy for hydropower, nuclear power and thermal power. With the additional assumption that hydropower runs at 80 percent loading, this led to increased system inertia if nuclear production was replaced by hydropower.

There calculation of the inertia constant could have been done in several other ways. The inertia constant for nuclear power is assumed to be 6,3 seconds, 4 for thermal power, and 3 for hydropower. The inertia constant for hydropower could have been the only unknown variable when the system inertia constants were to be decided. The calculations for these assumptions are presented below. In the original calculation of the system inertia constant, the production in Denmark was not included in the original calculations. This is included as thermal power in this situation. In the reference scenario, hydropower comprises 36586 MW, nuclear power comprises 9420 MW and thermal power comprises 5377 MW. The production from Denmark is 4311 MW.

$$H_{hydro} * \frac{36586}{0{,}8 * 0{,}9} + 6{,}3 * \frac{9420}{0{,}9} + 4 * \frac{5377 + 4311}{0{,}9} = 370000$$

$$H_{hydro} = 5{,}13$$

The constant for hydropower is still large, but reduced. The previous calculations gives a much larger kinetic energy contribution form hydropower than nuclear power. Below is the calculation for the original and new values presented for 1000 MW production.

$$H_{original,nuclear} = 5{,}47 * \frac{1000}{0{,}9} = 6077\ MW$$

$$H_{original,hydro} = 5{,}47 * \frac{1000}{0{,}9 * 0{,}8} = 7597\ MWs$$

$$H_{new,nuclear} = 6{,}3 * \frac{1000}{0{,}9} = 7000\ MWs$$

$$H_{new,hydro} = 5{,}13 * \frac{1000}{0{,}9 * 0{,}8} = 7125\ MWs$$

The aim for the sensitivity study is to increase system inertia with an increased share of nuclear and thermal power, because the theory found on the subject assumes that this is the case. With these new way of calculating the system inertia, the difference is only reduced. Hydropower still provides more system inertia than nuclear power

Another way to perform the calculation is to keep the relation between the different inertia constants constant.

The calculations if the inertia constants could also have been done with the following method:

$$H_{hydro} = \frac{370000}{\frac{36586}{0,8*0,9} + \frac{6,3}{3}*\frac{9420}{0,9} + \frac{4}{3}*\frac{5377+4311}{0,9}} = 4,24$$

$$H_{nuclear} = 4,24*\frac{6,3}{3} = 8,91$$

$$H_{thermal} = 4,24*\frac{4}{3} = 5,66$$

This change gives a better description for the contribution each power source has to the system inertia.

To compare this alternative method of calculating the kinetic energy in the system, some results are recalculated, to compare the original results and the new results.

5.5.1 Scenario 2C

From scenario 2, especially the effects when the production portfolios were compared are interesting with a different way to calculate the system inertia. Below is the calculation of the inertia as done in the original scenario

$$H*S = 5,47\ s*\left(\frac{9118\ MW}{0,8*0,9} + \frac{10127+1854}{0,9}\right) = 142,1\ GWs$$

The new system inertia is again based on the production in the system. Here the production by hydropower, nuclear and thermal are all presented with their own inertia constant

$$H*S = 4,24*\frac{9118}{0,9*0,8} + 8,91*\frac{10127}{0,9} + 5,66*\frac{2059}{0,9} = 165,6\ GWs$$

The changing production portfolios are especially interesting to compare with different ways to calculate kinetic energy. Scenario 2C was there tested once more with the new way of calculating inertia. Table 23 shows that the system inertia increases with an increasing share of nuclear power. The production portfolios are the same, but the kinetic energy is different from the original scenario.

Table 23: The same production portfolios from scenario 2, but with a different amount of kinetic energy.

Production portofolios[MW]						
% hydro	Nuclear	Hydro	Thermal	Wind	Total	Kinetic energy [MWs]
50,4	9127	11118	854	939	22038	161201
41,4	10127	9118	1854	939	22038	165611
36,3	11000	8000	2100	938	22038	169218
31,8	12000	7000	2100	939	22039	173229
22,7	14000	5000	2100	939	22039	181251

For the three last scenarios, the FCR was and still is the limiting factor.

In the earlier test, the fault could be 1000 MW with a share of hydropower of 41,4 and a proportional gain of 3,1. However, with the increased inertia, the frequency response will never fulfil the demands regarding the recovery time.

When the proportional gain is increased, it do not affect the fault the system can withstand when the hydropower share is 50 percent. When the hydropower share is 40 percent, the incident the system can withstand has increased with 100 MW.

The lower scenario never fulfilled the demand regarding the FCR. Not even with 100 MW lost production and no incident are given for these scenarios.

Table 24: The table shows if the scenarios listed in the left columns meet the demands for frequency response when losing a production unit. The proportional gain is 3,1. The green colour means the demand is fulfilled, the yellow means it is the limiting factor and the red means it is not fulfilled.

Results simulations, Kp=3.1						
% hydro	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
50,4	1150					
41,4	1000					
36,3	-					
31,8	-					
22,7	-					

Table 25: The table shows if the scenarios listed in the left columns meet the demands for frequency response when losing a production unit. The proportional gain is 4

Results simulations, Kp=4						
% hydro	**DI[MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
50,4	1300					
41,4	1200					
36,3	-					
31,8	-					
22,7	-					

5.5.2 Scenario 3A

Some of the results from scenario 3A are simulated one more time with the alternative way of calculating the kinetic energy in the system. Figure 71 shows the frequency response for the new results, and Table 26 gives the dimensioning incidents for the old and new results.

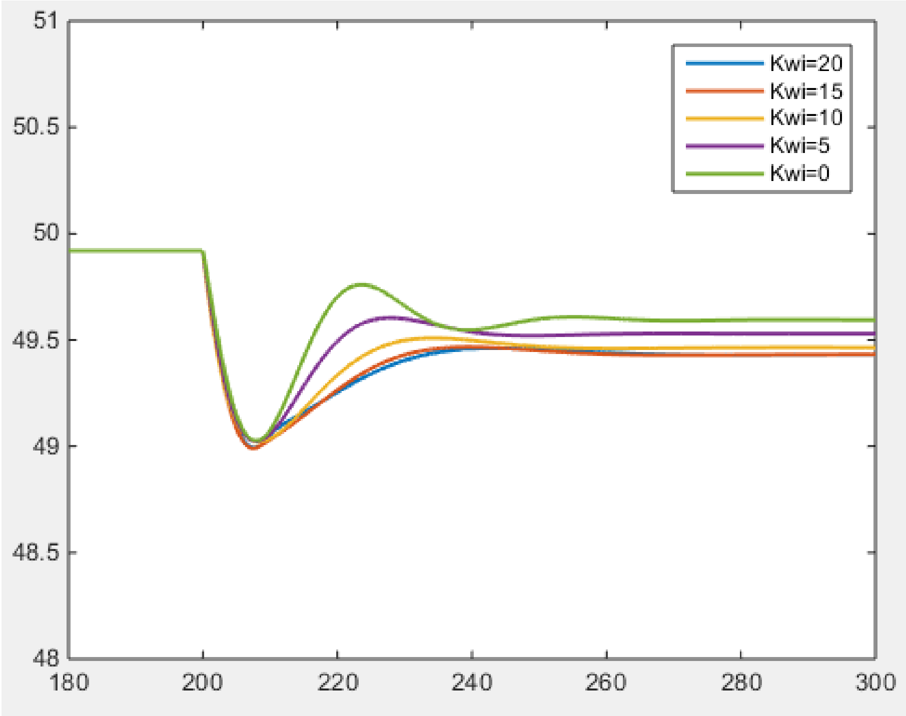

Figure 71: The frequency response for the scenario including synthetic inertia with the new kinetic inertia amount. The graph shows the frequency response for the different maximum fault for the different values of K_{WI}.

Table 26 shows very well the effect of increasing the inertia. The recovery time for the frequency increase with an increased inertia, while the maximum frequency deviation stays almost the same for the same loss of production.

The frequency bias that is featured as *R* in the table is very sensitive. In the original scenario it is marked green, while in the new scenario is yellow or read. All the values are about 3000 MW/Hz. In in the original scenario, they were 3050 MW/Hz which made them green and not yellow.

Table 26: Compares the new results for the simulations in scenario 3A.

Results simulations, P=22661 MW, H=122,6 GWs						
Kwi	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1000					
5	1200					
10	1400		49,47			
15	1450		49,47			
20	1450		49,47			
Results simulations, P=22661 MW, H=135,3 GWs						
Kwi	**DI [MW]**	**Freq>49**	**Stab freq>49,5**	**5 sec**	**30 sec**	**R**
0	1000					
5	1200					
10	1400					
15	1500					
20	1500					

Comparing the frequency responses for different production portfolios towards each other is an interesting result from scenario 3A. This analysis was performed one more time with new inertia values. Table 27 shows the production portfolios for the responses that Figure 72 shows. The original wind production that provides synthetic inertia is simulated as respectively hydropower and nuclear power in the alternative production portfolios.

Table 27: The production portfolios for the simulations shown in Figure 72.

Production [MW]			
Name of scenario	Wind	Hydro	Nuclear
Large scale Hydropower	8846	13539	8846
Small scale Hydropower			
Thermal	1958	1958	1958
Nuclear	7164	7164	11857
Wind	4693		
Total	22661	22661	22661
Inertia, original [GWs]	122,6	158,3	151,1
Inertia, sensitivity [GWs]	135,3	162,9	181,8

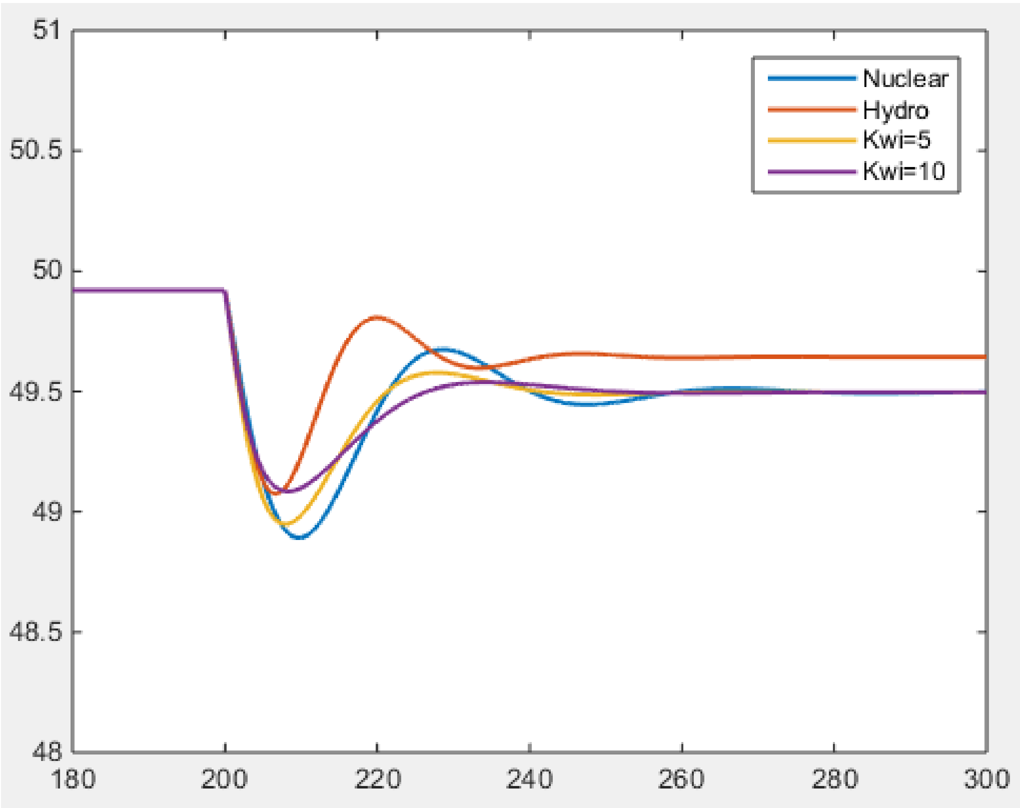

Figure 72: The frequency responses for different production portfolios. The total production is 22661 initially and at 200 seconds, all the cases lose 1300 MW production.

Figure 72 shows that nuclear power still is the worst production unit in the power system regarding the maximum frequency deviation. The difference from wind power with synthetic inertia and hydropower is modified with the new calculation of kinetic energy.

However, the conclusion is the same.

6 DISCUSSION

This study focuses on tomorrow's challenges regarding frequency stability and reserves in case of a large disturbance in the Nordic synchronous system. The analyses have tested how the system will be able to withstand different losses of generation with the expected development of the power supply. The studies are limited to the transient response after a disturbance. Two main concepts are considered to see if the system withstands the tested fault: The **system inertia** and the requirements for the **FCR-D response**. If the frequency does not follow the current requirements regarding these topics, this thesis concludes that the operating condition is unacceptable and measures have to be taken.

When the system inertia limits the dimensioning incident that the system can withstand, it means that the frequency drops to 49,0 Hz during the transient period. It was chosen to use 49,0 Hz as a threshold line, but there has been discussed among the system operators to use 49,2 Hz as a threshold value [15]. All the scenarios started at 49,9 Hz as a worst case with respect to normal operation. The test was to find how much production the system can lose without causing a larger frequency deviation than 0,9 Hz during the transient period. Different compositions of power sources lead to different system inertia due to their assumed kinetic energy. If the frequency dropped below 49,0, measures were taken or the fault was changed.

When the FCR-D limits the response, the system just manages to provide 50 % of the original lost power after 5 seconds. The hydropower is the only provider of the FCR-reserves, except in scenario 3C when the emergency power also contributes with FCR. After 30 seconds 100 percent of the lost power should have been replaced by the FCR-D reserves. The frequency bias should be at least 3000 MW/Hz in the range 49,9 to 49,5 Hz.

The applied method was simple: if a loss of production did not satisfy these demands, the system was changed or the dimensioning incident had to be reduced.

First, the results give a rough estimate on how different factors can worsen or improve the frequency stability in case of a disturbance. The results give an indication for which operating conditions that can be challenging regarding frequency stability and how large disturbances the system can withstand under different operating conditions.

This study is also among the first that look at the relation between FCR-D and kinetic energy. The method shows how these factors relate to each other and limits the fault the system can withstand for the system in different ways.

The study is a worst-case scenario, and some assumptions that are made are pessimistic. One example is to always assume initial frequency at 49,9 Hz when a disturbance (loss of generation) occurs

6.1 LIMITS FOR THE MODEL

6.1.1 Tuning of the model

Some of the assumptions made in the tuning of the model are uncertain. Most of the uncertainties are related to the actual reserves and amount of inertia in the different power plants. This is discussed below.

A simplification regarding the inertia constant is the production used when the amount of kinetic energy was found. Denmark is not included in the model because the NORDIC-44 model does not include Denmark. In the sensitivity study, this fault was corrected and it did not influence the results significantly.

Some information to achieve more reliable result is also missing. Regarding the response from the real system in the reference scenario, the emergency power that may have been provided by the HVDC cables is not documented. It is a possibility that this have affected the frequency response.

The model was tuned when the production in the system was around 50 GW. The scenarios that were tested had a production around 20 GW. The system probably behaves differently regarding the governor and the droop setting at low load. These factors are flexible and it was assumed that during low load, these factors adjust to ensure a better frequency response according to the requirements.

6.1.2 Inertia constant and amount of kinetic energy

The amount of the kinetic energy was calculated to be 344 GWs, but the tuning of the model resulted in an amount of 370 GWs. Because of the similarity between the real and modeled frequency response, this is considered as an acceptable deviation. However, the relation between the assumed synchronously connected capacity and kinetic energy gives a system inertia constant of 5,47 seconds. There are many uncertainties to both the system inertia and the system inertia constant and how it is used for the new scenarios. A parallel study performed with the same reference scenario but in a different model, tuned the system into having 282,5 GWs. The difference is almost 100 GWs and this gives uncertainties to the results. The assumed connected capacity can also be wrong.

Another large uncertainty is how the system inertia constant was used further on in the low load scenarios. To calculate the system inertia in the low load scenarios, the system inertia constant was multiplied with the assumed synchronously connected capacity. The connected capacity was calculated with the assumption that hydropower works at 80 percent loading and all other production works at 100 percent. The hydropower production is therefore divided by 0,8 to find the connected capacity. In addition, all the production are divided by the power factor 0,9. This assumption gives more credit to hydropower regarding FCR and system inertia than any of the other power sources. The production from hydropower contributes with more kinetic energy than nuclear and thermal power, in the original model. The assumptions made in the literature that was studied, assumes larger contribution from nuclear than hydropower. This assumption has large influence on the scenarios were production portfolios are tested. Therefore, a sensitivity study was performed to see how this assumption affected the results.

The new inertia constant could be calculated in several ways, but two methods were tested. Because hydropower comprises 70 percent of the power production in the reference scenario, the inertia constant for hydropower was analyzed in more detail.

First; if the inertia constant for nuclear and thermal generation was determined to be their assumed values 6,3 seconds and 4 seconds, respectively, the inertia constant for hydropower was then calculated to be 5,13 seconds.

Secondly; by keeping the relation between the inertia constant the same as the relation between the constants given by Statnett, the hydropower is 4,24 seconds, the nuclear inertia constant is 8,91 and the inertia constant for thermal power is 5,66.

The later result differs most form the original method of calculating it, and it is also closest to the constants found in the literature study. These constants were therefore used in the sensitivity study.

To use the exact same constant Statnett uses in their calculation was also considered. However, it was chosen to use the calculated value instead. This choice was made because the model was tuned very well to the response from the real system. In addition, the parameters that affect the real response are not modelled in the reference scenario or the other scenarios, so the numbers had to correspond to the model and not the real system.

The results differ slightly between the two ways of calculating the kinetic energy in the system. The tendencies are the same, and only a few of the results were simulated both ways. The main conclusion did not change due to the sensitivity study.

6.2 Requirements for frequency response

The thesis considers the current requirements for the frequency response during disturbances. The requirements that are studied regard when the activation of the reserves should happen, and how much power reserves must be available.

Chosen demands to follow

The quality of the frequency response is tested against five requirements. The results are the largest faults the system can withstand without violating the requirements regarding FCR and inertia. The requirements are repeated below:

1) The transient frequency must never drop below 49 Hz.
2) The frequency must never stabilize at any lower frequency than 49,5 Hz
3) The FCR-D demand is divided into three categories
    a. 50 % of the size of the power imbalance must be compensated for within 5 seconds.
    b. 100 % of the power imbalance must be compensated for within 30 seconds.
    c. The frequency bias must be at least 3000 MW/Hz.

It is not looked into how the producers comply with the current requirements. The study has analysed situations where some of the factors are just below their threshold. This is also interesting because there are several factors not included in the model that might affect the frequency response.

The droop setting will control requirements 2 and 3c. Changing the droop setting has not been investigated, because the thesis manly investigated the transient response after a disturbance. The requirements are included to show how they change when the loss of production increases or the production portfolio changes.

The droop percentage was lowered from 12 to 8 percent from the reference scenario. This reduced the effect of the droop on the result. It also seems reasonable to have a more static system during low loads to minimize the stable frequency deviations.

With respect to the requirement that 100 % of the reserve capacity must be activated after 30 seconds, it is not taken into consideration if it requires that 100 % of the FCR must be steadily provided. In this thesis, it is enough that that the peak value for the power response is reached. The power response was rarely stable, and therefore it would have been very unsuccessful to use this as the limiting factor every time. The 30-second rule was always fulfilled during the simulations with the assumption that the supply of FCR reserves did not have to be stable after 30 second. There is a significant difference between a well-damped system and a system that oscillates. During the incidents with low inertia and a high proportional gain in the governor, the frequency and power supply oscillate for several seconds after the initial peak response. That implies that the system does not provide more than 100 % of the FCR constantly after the peak. With a well damped system will provide at least 100 % of the required power after the peak.

Ignored requirements

In the reference scenario, the frequency bias was over 8000 MW/Hz. This probably has to do with the system providing both FCR-N and FCR-D. The study also shows that increasing the production has a very favorable effect on the frequency bias in the system. In the reference scenario, the system frequency was 50,13 Hz before the fault which can have provided extra kinetic energy to the system just before the fault occurred. In this study, FCR-D and FCR-N are totally divided and only FCR-D is revised.

6.3 WHAT AFFECTS THE FREQUENCY RESPONSE

The study wanted to show how the frequency response could be manipulated to react differently, without changing the dimensioning incident or the production portfolio. The main factors investigated are the governors' settings, synthetic inertia and emergency power.

6.3.1 The governor

The governor is a central part of this study, and that is the case in the real system as well. However, some of the effects shown in the simulation are not necessarily true. The governor and its parameters affect the frequency and can control how available spinning reserves react to an incident.

By increasing the proportional gain in the governor, the FCR-D response is faster. This was tested in alternative 2B. This helps fulfilling the 5 seconds requirement without increasing the share of hydropower in the power supply. However, it is worth noting that an increased K_P can lead to unwanted excitation of dynamics that are not modelled in this study.

It is not looked into how fast the automatic tuning of the proportional gain in the governor are. The effects are presented to show the positive and negative effects of a high and a low proportional gain. An important property of the proportional gain is that increasing it shortens the recovery time, reduces the maximum frequency deviation, but keeps the frequency oscillating for a longer time. The fault the system can withstand increases if the proportional gain increases. K_P activates the FCR-D faster and more powerfully, and this property is reduces the maximum frequency deviation.

The scenarios uses a proportional gain of 3,1. This was a choice based on the interface between the inertia limiting the maximum fault and the FCR-D limiting the dimensioning fault. This means that, in scenario 2B, it was shown that with a lower proportional gain than 3,1, the 5-second response was not satisfactory. Above it, it was more than satisfactory when the frequency deviation was 0,9. However, increasing K_P permits higher dimensioning faults. Since the original gain in the reference scenario was 2, and it is unsure how stable the system is with larger K_P, increasing the proportional gain was not investigated further in scenario 3. Increasing it could have given a faster response in the later scenarios. Increasing the proportional gain can solve the problem of systems that can no withstand the dimensioning incident of 1400 MW.

An important difference to notice in the results is the fundamental difference between K_P and the proportional gain in the synthetic inertia, K_{WI}:

K_{WI} is the boosts of the inertial reaction. An increase in synthetic inertia slows the system down in the same way as natural inertia. This has a negative effect on the recovery time for the frequency.

K_P boosts the FCR reaction. This shortens the recovery time and activates the FCR faster, which will reduce the maximum frequency deviation.

6.3.2 Synthetic inertia

Including synthetic inertia from wind in the power supply results in a better response, than if the same amount of power was provided by nuclear power, with the assumptions made in this thesis.

There are some modifications to the simulation. The literature found regarding synthetic inertia assumes a gain (Kwi) of ten. This requires good technology and it is not looked into if this is realistic.. Mainly, the manufactures have published estimates on how synthetic inertia can contribute in the future. This gives some uncertainties to the result.

The input regarding wind power production to the model does not include any information about the total installed wind power. The input is the expected production. It is assumed that the wind power with synthetic inertia control can increase the production with ten percent. If the wind energy comes from a few wind parks with full production, this can be true. If the energy comes from many wind parks that only operates at 30 percent of their rated energy, it is not likely that they can increase their power output with ten percent.

On the other hand, the results show that the impact of synthetic inertia may contribute with large and important reserves. The graphs show a huge difference of the frequency reaction with and without synthetic inertia.

Another favourable property of synthetic inertia is the controllability. Units equipped with synthetic inertia can control when and how they should react, to some extent. Natural inertia cannot be controlled. The timing for the recovery energy period for synthetic inertia can therefore be tuned to occur at the same time as the hydropower overshoot. This can be adjusted beneficially regarding the requirements for the frequency.

The comparison of synthetic inertia to hydropower and nuclear power are discussed in 6.4.2 Scenario 3.

6.3.3 Emergency power

Emergency power contributes with an extra regulating power that can increase the stable frequency. With both synthetic inertia and emergency power provided by HVDC cables, this can be an important contribution with a low amount of hydropower in the system. In this thesis, the effect did not have any important role, since there was little published work regarding this, it did not seems appropriate to model the emergency power with an advanced loop. The emergency power are modelled as a contribution to FCR-D.

6.4 WHAT WILL THE DIMENSIONING INCIDENT BE IN THE FUTURE

The scenarios look into which incidents the system withstands with the maximum frequency deviations and the current requirements for FCR-D. The static frequency deviation before the secondary reserves are activated is also measured, but this can be changed by adjusting the droop setting. The droop setting will also affect the frequency bias. This has not been the focus for the analyses.

The dimensioning incident for the future is meant as a guidance to which losses of production the system can withstand during different operate conditions. The dimensioning incident is 1400 MW in the synchronous system today, and it is expected to increase to 1650 MW when a new nuclear power plant in Finland comes into operation. This work looks into how large incidents the system can withstand, and what limits the possible incident – the level of inertia or the requirements for FCR-D.

6.4.1 Scenario 2 – Low load

Scenario 2 was a low load scenario with conventional power sources.

Scenario 2A did not change any of the parameters from the reference scenario and had the original composition of power producers from June 23rd, 2013. The droop was 12 percent and the proportional gain was 2. The system with these parameter cannot withstand a loss of 1400 MW before the total production is past 31 000 MW. The scenario needed an amount of 700 GWs kinetic energy to withstand an incident equal to 1400 MW. The calculated amount of kinetic energy is 142, 1 GWs. It is not realistic to change the level of system inertia that much. The system could withstand a loss of 800 MW with its current settings.

Without changing the production portfolio, it is still possible to change the amount of the kinetic energy in the system. By definition, the kinetic energy is decided by the total capacity of the synchronously connected generators and their inertia constant. By decreasing the output ratio for the generators (meaning synchronizing more power generator), the apparent power increases. However, it is not economically desirable to run many generators at reduced loading. It is important to note that the synchronously connected capacity is an assumed number.

The original composition from scenario 2 can withstand a higher fault if the proportional gain in the governor for hydropower is increased. This was shown in scenario 2B. With the proportional gain increasing from two to five, the dimensioning incident the system can withstand can be increase from 800 to 1300 MW. It is seen that the proportional gain (the inverse of what is sometimes referred to as the transient droop) of hydro governors has a significant impact on the dynamic performances. However, from the analysis with this model it is not possible to conclude on how a larger gain would affect the stability of the system, in particular related to power oscillations at frequencies above 0.1 Hz. To increase the gain in the hydro governors can still be an important method to increase the frequency recovery performance, if the stability issues are addressed and solved.

In scenario 2C, where different production portfolios were tested, the maximum dimensioning incident is 1000 MW for the original composition of different power supplies. The original composition is the composition from June 23rd. In this portfolio, the hydropower comprises 41 percent of the power supply. The proportional gain is 3,1. With an increased share of hydropower to 50 percent, the dimensioning incident could be 1100 MW. By increasing the proportional gain to 4, the numbers are 1100 MW for 41 percent hydropower and 1300 MW for 50 percent hydropower. This scenario stresses the importance of hydropower in the power supply. This aspect was analyzed in the sensitivity study with different system inertia for the different compositions, and the results were similar. This can be an indication that in low load situations, FCR-D is just as important as the inertia amount to minimize the frequency deviation during the transient period. In the sensitivity study, the system inertia is reduced by increasing the share of hydropower, but the dimensioning incident is still increasing despite this.

In scenario two, in the original composition of power sources with 40 percent hydropower, the nuclear power has a larger contribution with 10127 MW than in the reference scenario were the nuclear production units deliver 9420 MW. In the sensitivity study, the kinetic energy was 165,6

GWs, and in the original scenario, the kinetic energy was 142,1 GWs. This did not affect the results significantly.

Scenario 2D shows a linear relation between the dimensioning incident and the production. This is caused by the linearity in the model, and the relation between increased production and increased fault the system can withstand is probably more complex in reality.

6.4.2 Scenario 3 – future scenario with synthetic inertia

This scenario presents how synthetic inertia contributes with active power during a disturbance. The simulations show that the synthetic inertia can contribute with large amount of active power during the transient period. The synthetic inertia increases the recovery time similarly as natural inertia. However, synthetic inertia has an active power contribution that does not affect the frequency negatively. The natural inertia delivers more electric energy than received mechanical energy to compensate for the imbalance of production and load. As long as the natural inertia compensates for the power imbalance, the frequency reduces. The synthetic inertia responds to the negative derivative of the frequency, but does not contribute to reduce it. This is a favorable effect regarding the maximum frequency deviation.

Scenario 3 tested synthetic inertia from wind power in alternative 3A, increasing the share of small-scale hydropower in alternative 3B and the contributions from HVDC in alternative 3C. The original production portfolio was used in scenario 3A and later changed to contribute small-scale hydropower and HVDC for alterative 3B and 3C.

The dimensioning incident in the original portfolios was 1300 MW in alternative 3A. If the frequency could stabilize at 49,47 Hz, just below its threshold, the dimensioning incident could be 1400 with a K_{WI} equal to 10. Several mechanisms like droop and emergency power that can contribute to a higher stabilization level, so this factor is not a concern. At 1400 MW, the maximum frequency deviation or the system inertia level is limiting the dimensioning incident. Without synthetic inertia, the dimensioning incident cannot be larger than 1000 MW.

In scenario 3A, a comparison between the contributions from nuclear, hydropower and synthetic inertia were compared. The total production is 22661 MW and about 10 000 MW is nuclear and thermal, about 8800 MW is hydropower and the last 5000 MW is “flexible”. This production is moved from wind to hydropower and to nuclear power. The frequency responses are compared when a fault of 1300 MW occurs. When the flexible power was wind power with synthetic inertia, the frequency deviation was smaller compared to when the flexible power was nuclear power. When the flexible power was hydropower, the frequency deviation was at its minimum. This comparison was also researched in the sensitivity study where the kinetic energy contribution from hydropower was reduced and the contribution from nuclear power was increased. Despite this change, the synthetic inertia is still better than nuclear, considering the maximum frequency deviation. Hydropower still contributes the most to reduce the maximum frequency deviation.

It is seen that even though hydropower has a lower kinetic energy contribution in the sensitivity study, it reduces the transient frequency deviations better than synthetic inertia and nuclear power. This is because inertia is sufficient to slow the frequency drop until the large FCR-contribution from hydropower will activate and stop the reduction of the frequency. In this study, FCR is only provided by hydropower. This indicates that the amount of system inertia is not the most crucial value. The results can indicate that a very small amount of system inertia is necessary to prevent large frequency deviations the first seconds. The most important parameter to avoid large frequency deviations is a strong FCR-response that stops the power balance to rely on the system inertia.

The comparison of hydropower, synthetic inertia and nuclear power in this work underestimates the real contribution from nuclear and thermal power. It is possible for these power sources and their governors to contribute with active power reserves. In this study, these sources are modelled as positive loads, which do not contribute with FCR and work at 100 percent loading. This is not necessarily true.

When half of the Norwegian conventional hydropower was replaced by small-scale hydropower in alternative 3B, the FCR-D was definitely a problem. The small-scale hydropower was treated as nuclear and thermal power in this case, which have an inertia constant of 5,47 seconds in this study. This underestimates the loss in kinetic energy caused by this replacement, but the lack of FCR-D in such operating conditions is still the main issue. With the original portfolio from Statnett and if the frequency bias requirement is ignored, the system cannot withstand a fault larger than 800 MW. Even though the droop setting can affect the FCR-D response, the results clearly show that the FCR will be an issue during such a scenario. By increasing the production, the small-scale hydropower did not cause problems with the same percentage small-scale hydropower. This shows that there must be a minimum amount of hydropower.

In scenario 3C, when the HVDC contribution is included, the scenarios first include 85 percent import for the Norwegian cables, which is 4420 MW. This replaces conventional hydropower in Statnetts worst-case scenario. Hydropower contribution was originally around 8800 MW but half is replaced by HVDC import. This is unrealistic due to previous results, so the import is reduced to 3000 MW. During the import of 3000 MW, the system almost withstands a loss of 900 MW. If the FCR-D requirement is totally ignored, the system can at this operating point withstand a loss of 1400 MW production support with synthetic inertia from both wind and HVDC.

How realistic it is in the Nordic power system, that relies all the FCR reserves on hydropower, to reduce hydropower to 5000 MW is uncertain. For now, in this simulation, it seems irresponsible to reduce the hydropower that much. First, in scenario 3C, the HVDC import replaced hydropower from the conventional hydropower. Next, the HVDC replaces wind power. With the wind power fully replaced by HVDC that provides synthetic inertia and emergency power, the system can almost withstand a loss of 1400 MW production and still fulfill most of the demands regarding frequency quality. The synthetic inertia from HVDC does not need recovery energy from the grid after the synthetic inertia contribution. This makes this a better alternative. However, the HVDC-cables in this thesis are modelled as connections to other synchronous grids. The state of the synchronous system that should deliver synthetic inertia and emergency power is not revised.

These scenarios assume large investments in synthetic inertia, both for HVDC and wind power. It has successfully been installed some version of synthetic inertia for the HVDC cable that connects Namibia and Zambia. however, it was especially emphasized that this cable connected two weak grids. The Nordic synchronous area has a large share of conventional power sources. This limits the chances for investments in technology regarding unconventional frequency support.

6.4.3 Realistic outage in low load scenarios

The dimensioning incident is 1400 MW in the Nordic synchronous are today, and it is discussed to increase it to 1650 MW when Finland builds a nuclear reactor with that rating [13].

The results from this task shows that low load scenarios rarely can withstand a loss of 1400 MW production, but it is worth questioning if this is really necessary. The dimensioning incident is today the maximum power output for the largest production unit in the system. During low load, this production unit will most likely not have maximum output. In the two production scenarios at 22038

MW and 22661 MW, it is not likely that an incident of that scale will occur. In scenario 2, the largest output for one production unit in Norway was 535 MW. It could be satisfactory for the system to withstand an incident losing that amount of production. Output details for all the power plants in Finland and Sweden are not given, and the largest output for these countries is not known. Both the current and new notified dimensioning incident comes from nuclear or thermal power plants. They normally run at high output levels.

However, with an increased share of new renewable power plants an assumption is that the power production comes from several small power producers. This will decrease the possibility for a large outage.

6.4.4 Sensitivity study

The sensitivity analysis shows that in low load conditions, increasing the inertia contribution by calculating the total the total system inertia differently, does improve the ability the system has to withstand faults. Increased system inertia improved the dimensioning incident with 0-100 MW for both alternative 2C and alternative 3C. This can be added as a margin of error for the other scenarios that were not recalculated in the sensitivity study.

6.5 WILL THE REQUIREMENTS FOR FCR-D COVER THE NEED FOR INERTIA

Today, the necessary FCR are purchased by the system operators, the resulting frequency bias is registered, and it is assumed that the system inertia is sufficient. This system is already changing, and it will soon be able to measure the system inertia level for the system operators.

With an increasingly share of power sources that do not provide inertia, an important question is raised: Can the existing routine for buying FCR provide enough inertia as well, or must it be established new routines for providing enough inertia in addition to the FCR.

In the low load scenarios with a low share of regulating hydropower, the FCR-D is normally the limiting factor. With a higher share of hydropower in low load, it is seen that the maximum frequency deviation and the system inertia level limit the possible dimensioning incident.

With a low share of regulating hydropower, the outage the system can withstand is normally much lower than the current dimensioning incident of 1400 MW. If the system operators purchase FCR to withstand an incident of 1400 MW in low load, by fulfilling the requirements regarding FCR-D, the tendency is that in these operating conditions, the inertia is the limiting factor. If the FCR-D meets the requirements for an outage, it is uncertain if the system inertia level in sufficient to prevent the transient frequency to drop below 49 Hz. In other words, system inertia is often the crucial point in several operating conditions. The system operators must therefore address this topic and can no longer assume that the system inertia is enough.

If the proportional gain in the system is increased to meet the requirements for FCR-D, the results show that the limiting factor for the possible outage changes from being FCR-D to become the level of inertia. This shows that the FCR-D level does not necessarily cover the need for system inertia. Increasing the proportional gain do increase the possible dimensioning incident the system can withstand. At a high value of the proportional gain, the level of system inertia will limit the fault the system can withstand.

Low inertia can reduce the recovery time for the frequency and slow down the power response. The system inertia and the recovery time increase proportionally. If only FCR-D requirements are considered, a scenario with a very low inertia can be said to have a very good FCR-D response. This highlights a problem that can appear if the system inertia is not addressed differently than today.

To change the ability to withstand low frequencies in the transient period by increasing the system inertia, large amounts of kinetic energy are needed. In low load, the difference between the system inertia for different production portfolios does not change significantly. This was observed in the sensitivity study that the effect of the system inertia level was not very large. Scenario 2A showed that by only changing the system inertia to increase the disturbance the system could withstand from 800 MW to 1400 MW, the system inertia must increase from 142 GWs to 700 GWs.

FCR can be provided by hydropower and thermal and nuclear generators. However, it is registered in the power system that governors for nuclear and thermal power do not respond to frequency signals as well as the governors for hydropower [8]. Of course, the provision of FCR gives the hydropower a special advantage and is not comparable to nuclear power.

6.5.1 Scenario 2 – low load

In scenario 2C it is seen that when the hydropower comprises more than 40 percent hydropower, the inertia level starts being the limiting factor during low load in scenario two. This is with a proportional gain of 3,1. Increasing the share of hydropower is the most efficient way to increase the possible dimensioning incident and if this is the method used in low load scenarios, the requirements for FCR-D will not cover the need for system inertia. Increasing the proportional gain is also a method to increase the FCR. To manage a fault of 1400 MW in scenario 2C, the share of hydropower and the proportional gain must be increased. Hydropower can also run at a lower load, this will increase the synchronously connected power that benefits the FCR-response. When the sensitivity study for scenario 2C could withstand a fault of 1300 MW, the FCR was not an issue, but the frequency dropped to 49,0 Hz. This again implies that the inertia level must be considered when reserves are being purchased.

These results emphasize that it will be natural to have a system that have the inertia level as the limiting factor for the possible dimensioning incident. At these operating conditions, the system can withstand the largest faults. This indicates that the system inertia level should be a larger concern in low loads scenarios. When a sufficient FCR is provided to withstand a loss of production close to 1400 MW, the inertia level is the crucial factor.

6.5.2 Scenario 3 – future scenario

In scenario 3A, wind power constitutes about 25 percent of the power supply. In the situations where there was no inertia contribution from wind in scenario 3A, the inertia level was definitely the main problem that limited the possible dimensioning incident. In is expected that there will be several productions portfolios with a large share of power generation without natural inertia. For these situations, it cannot be assumed that the purchased FCR-D will provide enough system inertia. This was clear from scenario 3A were the possible dimensioning incident was 1000 MW if the wind power did not contribute with synthetic inertia. With active measure like adding synthetic inertia, the system could withstand a fault of 1400 MW.

However, in the sensitivity study, when synthetic inertia was added, recovery time for the frequency was a significant problem when the dimensioning incident dropped the frequency to 49,0 Hz. Adding synthetic inertia to the system increased the possible dimensioning incident with 400 MW, both in the original scenario and in the sensitivity scenario. When the requirement of 1400 MW is reached, it is the inertia level in the original scenario that limits the dimensioning incident. In the sensitivity study, which is assumed to have a better estimate for the system inertia, the system had reached a dimensioning incident of 1400 MW, the FCR-D was a larger problem than the system inertia.

This scenario also concludes that in the future it is not sufficient to assume enough system inertia as long as the FCR-D requirements are met.

7 CONCLUSION

This work contributes to clarify how the reduced system inertia due to new production portfolios will affect the frequency stability. The main problem is the low load scenarios and these are studied in this thesis. A simplified model of the Nordic power system has simulated the effect of system inertia, FCR from hydropower, synthetic inertia from wind and HVDC, and emergency power from HVDC. This model was tuned based on an actual response from the Nordic synchronous system.

It is observed that if the system at low load contains conventional power sources, the current FCR requirements for frequency recovery after a disturbance limits the dimensioning incident that the system can withstand. If the hydropower share (which is the only provider of FCR in this study) is larger than 40 percent, the frequency will drop below 49,0 Hz when the FCR-D requirements are the only factors being considered. This makes the inertia the limiting factor for the dimensioning incident. This result is found with the proportional gain in the governor for hydropower equal to 3,1. Increasing the proportional gain will have the same effect as increasing the share of hydropower since both increases the amount of FCR in the system. With a higher proportional gain, the system can have a lower share of hydropower and still meet the demands for FCR. When the proportional gain is 4, the inertia is the limiting factor when hydropower comprises 36 percent of the total power supply.

In the future, the share of power sources without natural inertia will increase. Wind power and HVDC are the largest power sources that are not connected synchronously to the system to provide natural inertia. During the low load scenarios, this will affect the system ability to withstand disturbances. A solution is for wind power and HVDC to provide synthetic inertia. In a low-load scenario, where the production is about 22000 MW and wind power constitutes 25 percent, the system ability to withstand a disturbance increases from 1000 MW without synthetic inertia, to 1400 MW with synthetic inertia.

The shift between inertia being the limiting factor and FCR-D being the limiting factor was also found at a share of 40 percent hydropower for the scenarios that included synthetic inertia. This has not changed from the scenario with conventional power sources only. The proportional gain was 3,1 as before.

The synthetic inertia has two main effects that make it favourable to the system. Synthetic inertia can be controlled with power electronics, while natural inertia cannot. In this way, the response can be tuned to happen when and how it is best for the frequency response. Synthetic inertia reacts to the negative derivative of the frequency, while the utilization of natural inertia causes the system frequency to decrease. Synthetic inertia does not contribute to the frequency reduction, as natural inertia does.

The new future dimensioning incident of 1650 MW was never reached in the simulations, but 1400 MW can be handled by the low-load scenarios if the problem is properly addressed when the operating limits and factors are decided.

In the low-load scenarios, it is seen that ensuring FCR-D is a more efficient way to minimize the maximum frequency deviation during disturbances, than having nuclear power plants providing inertia. This was the tendency both in the low-load scenarios and in the sensitivity analysis. The sensitivity analysis was performed to give more credit to the inertia contribution from nuclear power. Both the inertia level and the FCR-D level are close to their threshold in many of the alternatives. Buying more FCR-D improves both, while provision of more system inertia will slow the FCR-D response. Due to this effect, it is seen that active power contribution from synthetic inertia and FCR is more efficient to reduce the maximum frequency deviation than natural inertia from nuclear power. However, synthetic inertia slows the FCR-D in the same way as natural inertia, and can slow down the recovery response for the frequency.

When a system at low load can withstand a loss of production above 1100-1200 MW, the inertia is always the limiting factor and not the FCR-D response. In the future, providing enough FCR will not be sufficient to also ensure enough system inertia. This must be ensured in a different way.

8 FURTHER WORK

To improve this study, the model itself can be improved. First, the model can be tuned after a disturbance when the production is lower than in the current reference scenario. The reference scenario almost had twice the production and load, compared to the scenarios that were tested. This can have large effects on the system parameters. If the system can be tuned to an actual incident during low load, this will increase the reliability of the result. To look how the system behaves differently during disturbances during high load and low load would have been an interesting comparison.

The study can be expanded by setting requirements for the system inertia, and divide the response to fulfil the requirements among the countries, in the same method as FCR are divided among the countries. Further investigations of scenarios can be performed to find the limits for different operating conditions, also at high load and requirements can be developed based on this study and further studies.

The frequency reserves should also include FCR-N to investigate how FCR-D and FCR-N interact. The assumption in this scenario that during large disturbances, the only available reserves are the FCR-D is unlikely. However, it is the worst-case scenario that is important when operating limits are being decided.

For further works, the stability should be addressed better. By adding one extra hydropower unit and have different settings for the drop, the time constant and the proportional gain in the areas, will cause further instability during the recovery time for the frequency. This will show the negative effects of increasing the proportional gain better.

To get more reliable results, it is also an idea to see if it is economically possible to equip existing power plant with modern technology for synthetic inertia for example. This study assumed that all wind turbines could deliver synthetic inertia, which is not very likely by 2020.

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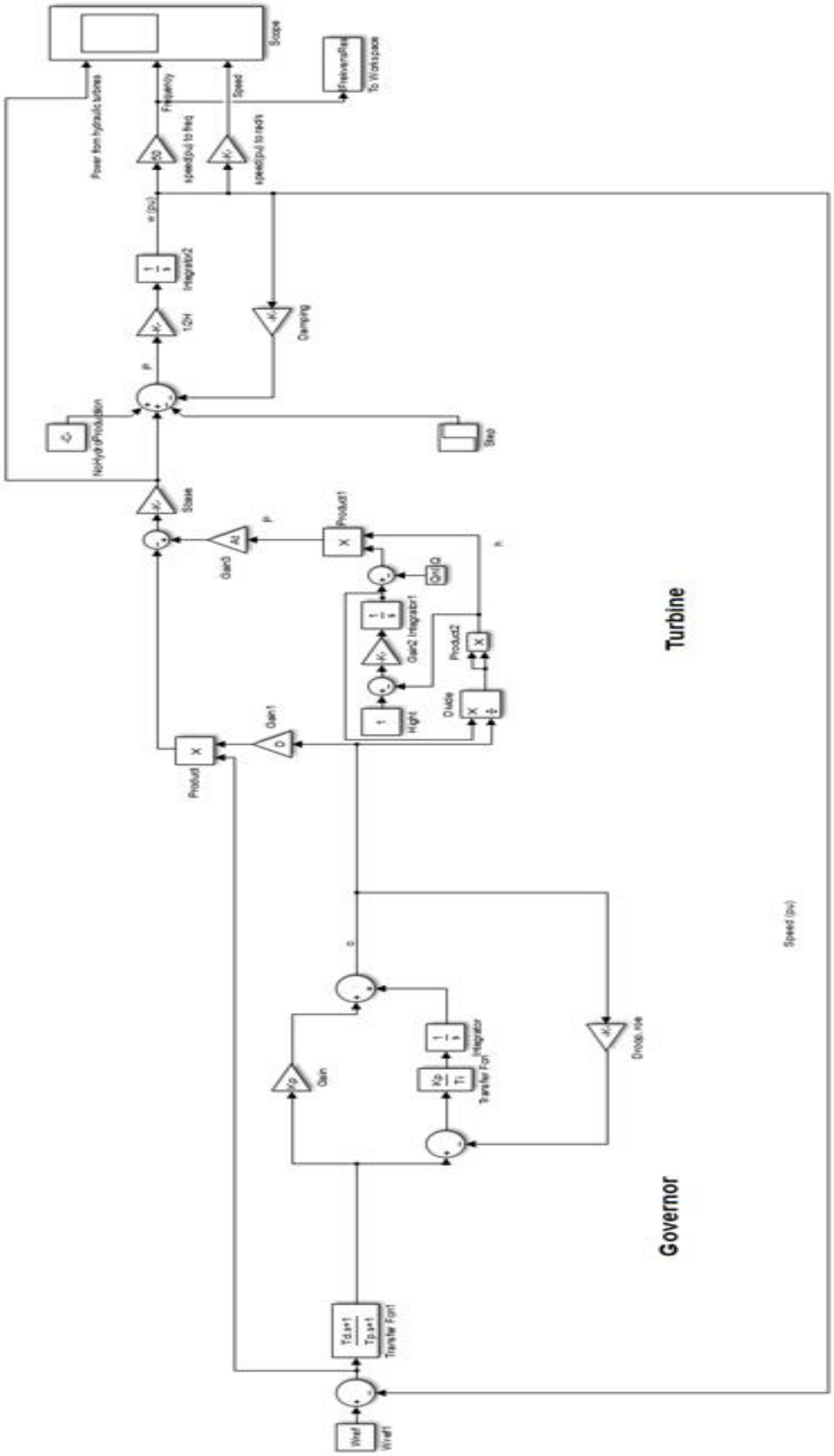
APPENDIX 1

```
%Script for a Simulink-model for the Norwegian energy system

%constants

%Generelly and system constants
pi=3.14;

Sbase=6944;
H=135838;
Damping=0;
Wsync=2*pi*50;
Wref=1.0555;                  %1.0876 - 900 MW
ThermalAndNuclearProduction=17039;

%Governor
Kp=5;            % 3-5
Droop=0.08;       % 0.04-0.12
Ti=5;             % 6-10    - stiller stigningstallet for å øke frekvensen
igjen etter et dipp
Td=0.1;               % 0.5-0    - Øker svingningene
Tp=0.9;             % 0.2-0


%Turbine
D=0;
Tw=1;
Qnl=0;
At=1;

%Load
Load_before_fault=22038;
Load_after_fault=22038+1300;
```



Scope
To Workspace
Frequency
Speed
Integrator2
1/2H
Damping
Step
Stase
Gain3
Product1
Integrator1
Gain2
Product2
Divide
Hight
Gain1
Product
Gain
Integrator
Transfer Fcn
Droop
Turbine
Governor
Speed (pu)
Wref