



REPORT

Future System Inertia 2

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ABBREVIATIONS AND SYMBOLS

Abbreviations

| | |
|----------|--|
| aFRR | automatic Frequency Restoration Reserves |
| BRP | Balance Responsible Party |
| CB | Circuit Breaker |
| CBA | Cost Benefit Analysis |
| CET | Central European Time |
| CGM | Common Grid Model |
| CHP | Combined Heat and Power |
| COI | Centre of Inertia |
| D-1, D-x | Day minus one, Day minus 'x' |
| DI | Dimensioning Incident |
| EMPS | EFI's Multi-area Power-Market Simulator |
| EMS | Energy Management System |
| EPC | Emergency Power Control (HVDC connections) |
| EU-ETS | European Union Emission Trading Scheme |
| FBF | Frequency Bias Factor |
| FCP | Frequency Containment Process |
| FCR | Frequency Containment Reserve |
| FCR-D | Frequency Containment Reserve for Disturbances |
| FCR-N | Frequency Containment Reserve for Normal operation |
| FFR | Fast-Frequency Reserves |
| FIR | Finite Impulse Response |
| FQ | Frequency Quality |
| FRR | Frequency Restoration Reserves |
| GL | Guideline |
| ID | Intraday |
| HVDC | High Voltage Direct Current |
| LFCR | Load Frequency Control and Reserves |
| mFRR | manual Frequency Restoration Reserves |
| MCA | Multi Criteria Assessment |
| NAG | Nordic Analysis Group |
| NC | Network Code |
| NTC | Net Transfer Capacity |
| NOIS | Nordic Operator Information System |
| NRA | National Regulatory Authority |
| PMU | Phasor Measurement Unit |
| PSS®E | Power System Simulator for Engineering |
| RGN | Regional Group Nordic |
| RES | Renewable Energy Sources |
| RoCoF | Rate-of-Change-of-Frequency |
| SCADA | Supervisory Control And Data Acquisition |
| SISO | Single-Input-Single-Output |
| SPS | System Protection Scheme |
| TSO | Transmission System Operator |
| UFLS | Under Frequency Load Shedding |

Symbols

| | |
|---------------|--|
| E_k | Kinetic energy |
| f | Frequency |
| f_{COI} | Center of inertia frequency |
| $f_{extreme}$ | The minimum or maximum instantaneous frequency |
| f_n | Nominal frequency |
| f_{start} | Frequency at the start of the disturbance |

| | |
|---------------------|--|
| $f_{steady\ state}$ | Steady-state frequency |
| FBF | Frequency Bias Factor |
| GD^2 | Moment of inertia |
| H | Inertia constant |
| H_{sys} | System inertia |
| J | Moment of inertia |
| P | Active power |
| P_e | Electrical power |
| P_m | Mechanical power |
| R_{FCR} | Regulating Strength |
| S_n | Rated apparent power |
| s | Laplace operator |
| t | Time |
| $t_{extreme}$ | The time the frequency reaches $f_{extreme}$ |
| t_{start} | Start time of the disturbance |
| ω | Angular velocity |
| ω_n | Rated angular velocity |

1. EXECUTIVE SUMMARY

1.1 INTRODUCTION AND SCOPE

The behaviour of frequency in the Nordic power system is highly dependent on the amount of kinetic energy in the system. All rotating machines connected directly to the Nordic power system contribute to this kinetic energy. As renewable generation, connected to the grid through power-electronic converters, begins to replace conventional generation - together with the increased HVDC import capacity in the system - the amount of kinetic energy in the system decreases. This has an impact on the ability of the system to resist the frequency changes due to imbalance between production and consumption.

The objectives of the Future System Inertia 2 project are to anticipate and to avoid the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures. The project scope includes four main tasks:

1. Experiences in other synchronous areas
2. Future kinetic energy estimation
3. Measures to handle future low kinetic energy situations
4. Improvement of inertia estimation and operational tools

The findings of those different elements are summarized below.

1.2 RESULTS AND CONCLUSIONS

Experiences in other synchronous areas

The structural changes identified in the Nordic power system are not unique, and similar changes are occurring in other systems. Small and medium-sized synchronous systems are likely to already have experience and knowledge how to handle the challenges. To benefit of the experience gained, a survey was sent out by the Nordic transmission system operators (TSOs) during the summer of 2016, with a result of 11 answers. More than half of the synchronous systems under survey (eight out of 12) indicated that the decreasing inertia is a challenge. Three systems indicate that they have no solution in place for dealing with low-inertia situations at the moment. Two systems have market-based solutions, while six systems have non-market-based solutions. For dealing with future low-inertia situations, more reserves, synthetic inertia (as an ancillary service for example), more flexible thermal units, adding connections to other synchronous systems, and services from battery storage, are mentioned as foreseen mitigation measures.

Future kinetic energy estimation

The impact of the changes ongoing and foreseen on the kinetic energy in the Nordic system, have been assessed by means of future market scenarios that have been defined by the Nordic TSOs for the years 2020 and 2025. In the year 2025, the total variation in kinetic energy values appears to be smaller than in 2020: the minimum values are higher than in 2020, and the maximum values are lower than in the year 2020. The difference between the forecasts of the two years can be seen from the probabilities of having a low-kinetic energy situation. In Table 1-1, the column with the 99 percentile, for example, indicates that in one percent of the time, the kinetic energy falls below the 120 GWs in 2020, and below 134 GWs in 2025.

TABLE 1-1: PROBABILITY OF HAVING A LOW-KINETIC ENERGY (GWs) SITUATION
THE COLUMN WITH THE 99 PERCENTILE, FOR EXAMPLE, INDICATES THAT IN ONE PERCENT OF THE TIME, THE KINETIC ENERGY FALLS BELOW THE 120 GWs IN 2020, AND BELOW 134 GWs IN 2025.

| Year | Kinetic energy in GWs below a percentile of the forecasted kinetic energy distribution | | |
|------|--|------|------|
| | 90 % | 95 % | 99 % |
| 2020 | 150 | 136 | 120 |
| 2025 | 159 | 147 | 134 |

Those results can be explained from the fact that the scenario 2025 has approximately 2 500 MW more system load compared to 2020. The increased load requires more production and not all is covered by wind and import. That also results in more synchronous production and thereby higher inertia. Another explanation to the increased inertia in 2025, is the kinetic energy from nuclear.

The simulation results indicate that low-inertia situations (below 120 GWs) will occur in the 2020 and 2025 Nordic power system; the number of hours where this occurs, seems to be limited though. This limited number of low-inertia hours does not provide a sound basis for introducing a market for mitigation measures.

Short-term forecasting: improvement of inertia estimation and operational tools

In order to have a real-time grip on the inertia in the system, all Nordic TSOs have implemented a kinetic energy estimation in their SCADA/EMS, whereas an online dimensioning incident determination has been implemented in the SCADA systems as well, within the framework of this project. With these online data available, a linear regression model has been implemented in the Finnish SCADA system (and shared with the other Nordic SCADA systems), for an online extreme frequency estimation, in case of a dimensioning incident in the system. The linear regression model is tuned on the basis of disturbance data in a roughly one-year period (from 2015-07-20 to 2016-09-28), consisting of 19 under-frequency and 26 over-frequency cases. The interaction of the model and the SCADA system has been implemented in such a way, that more advanced models may be implemented in the future, such as the one-machine equivalent of the power system, that has been developed for offline studies within this project.

Mitigation: measures to handle future low kinetic energy situations

Various mitigation measures of low-inertia situations are proposed and – by means of the one-machine equivalent simulation model – tested on their efficiency. An overview is provided in Figure 1-1.

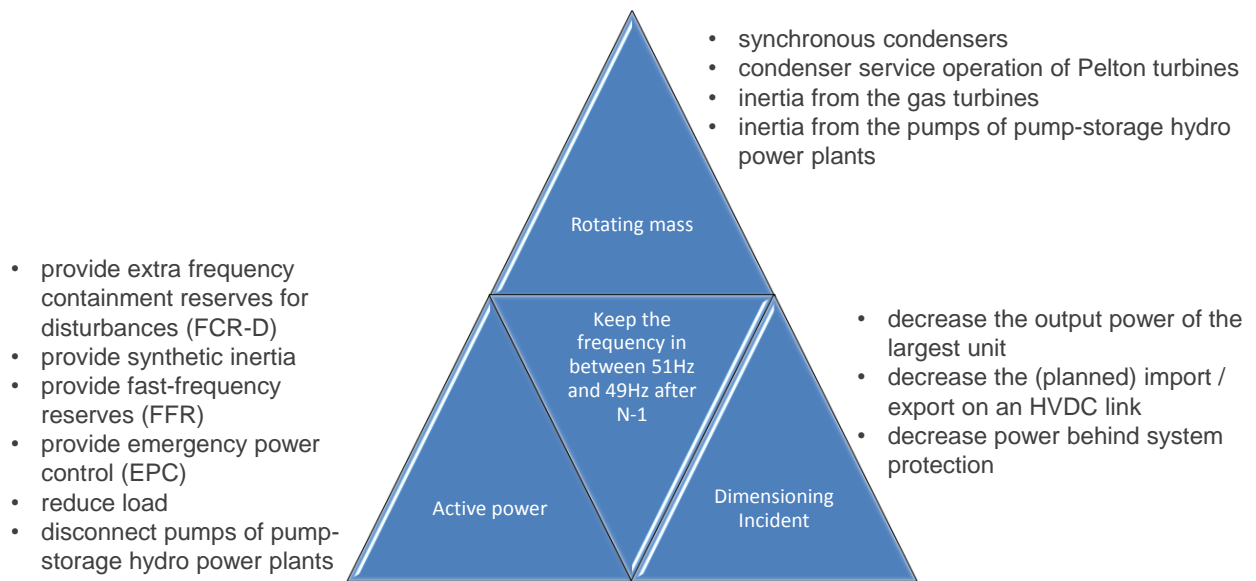


FIGURE 1-1 LOW-INERTIA MITIGATION MEASURES

The different mitigation measures have been evaluated on the basis of a Multi-Criteria Assessment (MCA). In an MCA, the different mitigation measures are scored on the basis of criteria, such in order to get a grip on the most promising ones. In this case the focus is on the most promising mitigation measures to be applied in 2020.

The reduction of the dimensioning incident, a measure already existing today, scores low in terms of cost and can be seen as a “plan B”. The “plan A” mitigation measures – being most promising in terms of potential, effectiveness, being sufficient, and cost that can be available in 2020 – consist of active power injections. The active power injection can be realized by:

- EPC; a redesign of the EPC settings has been proposed to make it a more efficient mitigation measure,
- Load disconnection, and
- Disconnection of pumps for hydro storage (being a special case of the load disconnection).

1.3 NEXT STEPS

Follow-up work of the Future System Inertia 2 project is suggested to consist of two pillars: an implementation project and a research project.

Implementation project:

- Implement the quick wins in terms of inertia mitigation measures (being the EPC, and load disconnection), in order to have measures at hand in 2020
- SCADA implementation continuation, including amongst others the use of the real-time situation of the EPC available in the extreme frequency computation
- Inertia forecast implementation: assess the expected kinetic energy in the system based on Common Grid Models

Research project:

- Towards a more dynamic assessment of Frequency Containment Reserves for Disturbances (FCR-D) and inertia needs
- Link to the Frequency Quality 2 (FQ2) project: inertia required to meet the quality criteria
- Link to the Revision of the Frequency Containment Process (FCP) project: coordination between fast-frequency reserves (FFR) and FCR-D (not separate them): be able to relax one at the expense of the other
- Practicalities: what is feasible, and what is the most promising technology for delivering FFR services
- Product definition and FFR requirements: e.g. proportional (closed loop) or pre-determined (power boost) power injection
- Develop a view beyond the quick wins ('target solution')
- Online situational awareness of the frequency stability (the 'big picture')
- Investigate / assess how much inertia is coming from the loads
- Continue the cooperation with other synchronous areas

2. INTRODUCTION

The power system is going through big structural changes which will challenge the way we traditionally think and operate the Nordic power system [1]. The changes will lead to the next generation power system, which will secure our future welfare, value creation and help us reach carbon-neutrality. The main changes are:

- The share of Renewable Energy Sources (RES) in the energy mix is increasing, and more energy will to a larger extent be produced by small-scale, renewable and distributed power plants. Large-scale wind farms are also foreseen. Most of those units are connected by means of power-electronic converters.
- Nuclear power plants are de-commissioned earlier than initially planned in Sweden, while Finland is constructing new
- Denmark and Finland have shut down many fossil-fuelled power plants
- The Nordic power systems will be physically more closely connected with Europe due to more interconnectors
- More coupled markets, including balancing
- More industrial loads are connected to the grid through power-electronic interfaces

The behaviour of frequency in the Nordic power system is highly dependent on the amount of kinetic energy in the system. All rotating machines connected directly to the Nordic power system contribute to this kinetic energy. As renewable generation, connected to the grid through power-electronic converters, begins to replace conventional generation - together with the increased HVDC import capacity in the system - the amount of kinetic energy in the system decreases. This has an impact on the ability of the system to resist the frequency changes due to imbalance between production and consumption.

The Nordic TSOs have studied inertia-related issues in their project 'Future System Inertia' phase 1. This project was an initial attempt to get a better understanding of the variation of kinetic energy in the Nordic power system and how it will change in the future. Also a tool to follow the real-time value of kinetic energy in the Nordic power system was created during the project. A project report presents the findings [2]. The work started in phase 1 has been continued, since there are still many questions related to the inertia of the power system and its relation to power system security.

There is a need to improve the predictability of the future with more renewable production and more HVDC connections to other synchronous systems. Furthermore, there is a need to study how critical situations with very low kinetic energy can be avoided and/or taken care of so that the system security is not endangered.

The objectives of the Future System Inertia 2 project are to anticipate and to avoid the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures (see Figure 2-1).

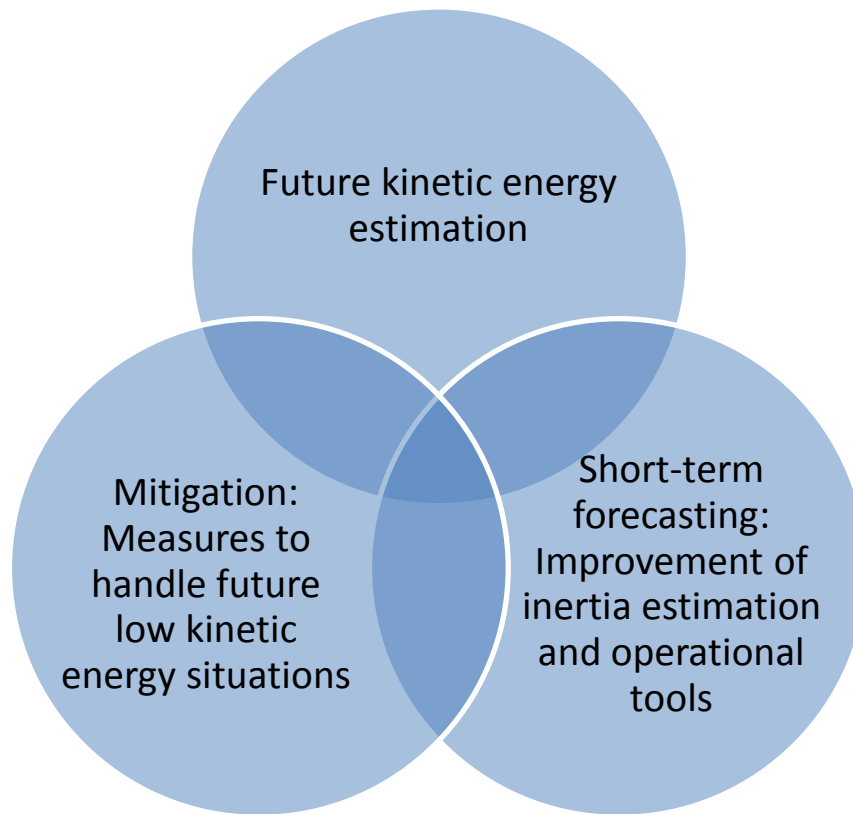


FIGURE 2-1 OBJECTIVES OF THE FUTURE SYSTEM INERTIA 2 PROJECT

2.1 SCOPE FOR THE PROJECT

The project scope includes four main tasks:

1. Experiences in other synchronous areas (Chapter 4)
2. Future kinetic energy estimation (Chapter 5)
3. Measures to handle future low kinetic energy situations (Chapter 6, 7, and 8)
4. Improvement of inertia estimation and operational tools (Chapter 9)

Those different elements are shortly introduced below.

Experiences in other synchronous areas

- Gather experiences from other synchronous regions by means of questionnaires, in terms of
 - How they assess the future inertia in their system
 - How they assess the actual inertia in the system
 - How they mitigate low-inertia situations (short-term, mid-term, and long-term solutions)
- Interviews with the most interesting responses received, to allow for a more detailed and in-depth insight

Future kinetic energy estimation

- Development of future scenarios, taking into account new HVDC links being commissioned, power plants being decommissioned, and a higher variable renewable power infeed
 - Mid-term (2020)
 - Long-term (2025)
- Market simulations to assess the production system and its kinetic energy
- Lumped-model frequency studies based on the minimum inertia cases identified, Frequency Bias Factor (FBF), and the present and future FCR-D requirements

Short-term forecasting: improvement of inertia estimation and operational tools

- Make a plan to improve the SCADA inertia measurements (in terms of new requirements / specifications and a timeline)
- Forecasting of system kinetic energy, Dimensioning Incident, and potentially the FBF, this being linked to the potential measures available at the time of forecasting. Different timeframes may prove useful in this respect, e.g. D-1 (after the production plan are available), D-3 (when load and weather forecasts are available), D-10/D-20 (to reduce the dimensioning incident). Or in other words: a means to trigger actions, with an indication of the mitigation needed
- Forecasting of the minimum instantaneous frequency for a dimensioning fault in real time
- Development of software tools; tools are developed to (at least) proof a principle. The tools can potentially be applied in the operational planning and/or control centre

Mitigation: measures to handle future low kinetic energy situations

- Investigation of options to control the Inertia, FCR-D, and Dimensioning Incident, and their interlinks
- Definition of FCR-D, when the 'normal' FCR-D is not sufficient (e.g. in low-inertia situations where the FCR-D from hydro sources is not sufficient and other sources are required)
- Investigation on a possible implementation of those options, by means of imposing requirements, procurement of services, or creation of a market
- An overview of the options, and the possible implementations on the short-term, mid-term, and long-term timeframes
- An evaluation of the options and/or mix of options by means of an MCA (Multi-Criteria Assessment), to be performed by the technical and market design experts. This is a 'qualitative' reasoning why a certain option is more preferred than another, based on qualitative reasoning (advantages and disadvantages), quantitative analysis (Hz, MW), and cost considerations (€) for example.

2.2 OUTLINE

This report addresses the tasks in the scope of the project, and provides some additional background for the ease of reading.

In Chapter 3 a presentation of theoretical background (based on the Nordic TSOs' 'Future System Inertia' phase 1 report [2]), the "big picture" (touching upon system stability), and the simulation model to assess the low-kinetic energy mitigation measures, and the tuning of its parameters, is given.

In Chapter 4 the responses received on a questionnaire, and information from follow-up interviews, have been summarized to present the experiences in the other (small to medium-sized) synchronous areas.

In Chapter 5 the findings of future kinetic energy estimations are presented for the years 2020 and 2025, whereas the year 2014 has been used to test the simulation chain from market scenario, market simulation, to kinetic energy estimation.

In Chapter 6 we zoom in on fast-frequency reserves (FFR) and synthetic inertia, and analyse their impact on frequency excursions. A similar analysis is performed in Chapter 7 for the emergency power control (EPC) provided by the HVDC links.

In Chapter 8 the measures to handle future low kinetic energy situations are presented and evaluated.

In Chapter 9 the short-term forecasting is touched upon: what tools need to be developed in order to assess which measures need to be activated, and when, in order to handle low-kinetic energy situations.

In Chapter 10 the conclusions of this study are presented, with references in Chapter 11.

In the Appendices, the questionnaire (of which the responses are presented in Chapter 4), information on the disconnection of electrical boilers and heat pumps in Sweden, and a discussion on the costs of ancillary services are provided.

3. BACKGROUND

This chapter provides a background for the report, thereby introducing various facets of, and grip on the topics inertia and frequency.

The theoretical background (Section 3.1) is based on the Nordic TSOs' 'Future System Inertia' phase 1 report [2]. The "big picture", touching upon system stability is elaborated upon in Section 3.2. The simulation model to assess the low-kinetic energy mitigation measures, and the tuning of its parameters, is described in Section 3.3.

An IEEE/Cigré task force defines frequency stability as follows. "*Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load*" [3]. Frequency stability rests on three main pillars, namely,

- Kinetic energy in the system
- Reserves
- Dimensioning incident

All these three have a great impact on the ability of the system to maintain frequency stability. Please note that history, policies, rules, and regulation define the playground to a large extent though, e.g. with regard to the frequency deviation where a generation unit is allowed to disconnect.

3.1 THEORETICAL BACKGROUND

Inertia of a power system is defined as the ability of a system to oppose changes in frequency due to resistance provided by kinetic energy of rotating masses in individual turbine-generators. To look at the inertia of a larger system with a large number of generators, it is convenient to look at kinetic energy of the system, which is the amount of energy stored in these rotating masses. In this chapter we look at inertia and kinetic energy and how they affect the behaviour of frequency in a power system.

3.1.1 INERTIA OF A SINGLE MACHINE

The inertia constant H describes the inertia of an individual turbine-generator:

$$H = \frac{1}{2} \frac{J \omega_n^2}{S_n} \text{ [s]} \quad (3.1)$$

where

J is the moment of inertia of a generator and turbine [$\text{kg}\cdot\text{m}^2$],

ω_n is the rated mechanical angular velocity of the rotor [rad/s],

S_n is the rated apparent power of the generator [VA].

The inertia constant is given in seconds and it can be interpreted as the time that the energy stored in the rotating parts of a turbine-generator is able to supply a load equal to the rated apparent power of the turbine-generator [4].

Sometimes the moment of inertia of a turbine-generator is given in gravimetric units GD^2 . Gravimetric units can be converted to joules using [5]:

$$J = \frac{GD^2}{4} \quad (3.2)$$

where GD^2 is the moment of inertia [$\text{kg}\cdot\text{m}^2$].

3.1.2 INERTIA OF A POWER SYSTEM

The inertia constants and rated apparent powers of individual turbine-generators can be used to calculate the inertia of a power system:

$$H_{\text{sys}} = \frac{\sum_{i=1}^N S_{ni} H_i}{S_{n,\text{sys}}} \quad (3.3)$$

where $S_{n,\text{sys}} = \sum_{i=1}^N S_{ni}$, S_{ni} is the rated apparent power of generator i [VA] and H_i is the inertia constant of turbine-generator i [s].

Motors connected synchronously to the power system also contribute to system inertia and can be taken into account in a similar way as generators.

Instead of expressing inertia of a power system in seconds, it is often more convenient to calculate the kinetic energy stored in rotating masses of the system in megawatt seconds (MWs). Then, Equation (3.3) can be written as:

$$E_{k,\text{sys}} = S_{n,\text{sys}} H_{\text{sys}} = \sum_{i=1}^N S_{ni} H_i \text{ [MWs]} \quad (3.4)$$

3.1.3 THE BEHAVIOUR OF FREQUENCY

Power changes in consumption and production, that affect the frequency, occur continuously. Small power changes are however only visible as noise in the frequency due to the mass of the synchronous generators in the power system. For large power imbalances, the system frequency can deviate further from the nominal. At the instant a large power imbalance occurs in the system, the frequency starts to change. If there is a sudden power deficit after for example a trip of a production unit, the deficit will be delivered from all synchronously-connected rotating masses. As the kinetic energy is dissipated, the speed of the rotors is decreased and thereby the frequency. How fast the frequency changes, depends on the change in active power and the system inertia.

The dynamic behaviour of an individual synchronous turbine-generator i can be described using the motion equation of a rotating mass (the swing equation):

$$H_i \frac{df_i}{dt} = \frac{f_n^2}{2S_{ni}f_i} (P_{mi} - P_{ei}) \quad (3.5)$$

where f_i is the frequency of generator i , f_n is the nominal frequency, P_{mi} is the mechanical power of turbine-generator i , and P_{ei} is the electrical power of generator i [4].

Equation (3.5) shows that an imbalance between the mechanical and electrical power of a turbine-generator results in a frequency derivative. The rate of change of frequency is defined by the imbalance and inertia of the turbine-generator.

Expressed in the Laplace domain, a linear one-mass model including load-frequency dependency interlinks a power change via the following transfer function to the frequency change:

$$\Delta f = \frac{f_n}{S_n(2H_{sys}s + kf_n)} \Delta P = G(s)\Delta P \quad (3.6)$$

where ΔP is the power imbalance between production and consumption, Δf is the frequency change, k is the frequency-dependency of loads and s the Laplace operator. This transfer function is a single-input-single-output (SISO) model of the power system.

Real power systems consist of a large number of generators and the network which connects the generators to the loads. Hence, when an imbalance in the system arises, the frequency is not uniform throughout the system (see Figure 3-4).

The following example illustrates how a system behaves when being subjected to a large power imbalance, why inertial response is important, and how the amount of inertia affects the behaviour of the system.

Example: Frequency control during large disturbances

For simplicity, let us assume that the power system consists of two generators and one load, all connected to a common bus as shown in Figure 3-1. Furthermore, zero losses and constant voltages are assumed. Generator G_1 provides Frequency Containment Reserves (FCR) and the load has a frequency dependence of 0.75 %/Hz i.e. the load decreases by 270 MW when frequency decreases by 1 Hz. The kinetic energy stored in the rotating masses of turbine-generator 1 is 200 GWs, and the kinetic energy of turbine-generator 2 is 8 GWs.

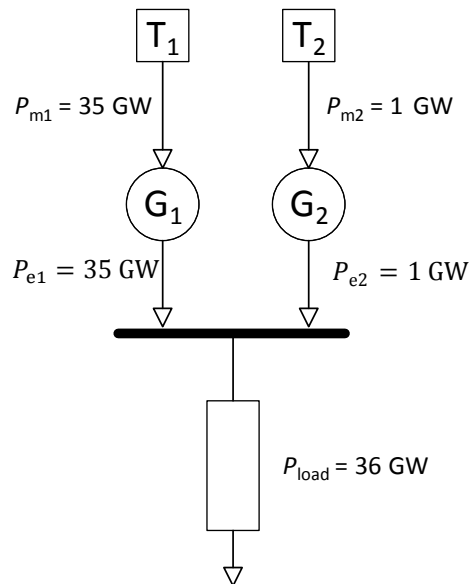


FIGURE 3-1 STATE OF THE POWER SYSTEM BEFORE THE TRIP

At time $t = 5$ s generator G_2 trips. Before the trip, the system is perfectly balanced. The frequency is at 50.0 Hz and the mechanical power from turbine T_1 and the electrical power of generator G_1 is 35 GW. The mechanical power from turbine T_2 and the electrical power of generator G_2 is 1 GW. In other words, the mechanical power from the turbines equals the electrical power from the generators, and balances the power consumed by the load.

$$P_{m1} + P_{m2} = P_{e1} + P_{e2} = P_{load} \quad (3.7)$$

After the loss of generator G_2 , generator G_1 has to supply the 36 GW load, so electrical power from generator G_1 has to increase by 1 GW to 36 GW. Immediately after the disturbance, mechanical power from the turbine T_1 is still 35 GW, as it will take some time for the turbine governor to react to the disturbance. In other words, the mechanical power from turbine T_1 is smaller than the electrical power from generator G_1 , and the turbine-generator begins to slow down according to Equation (3.5). When the turbine-generator slows down, the frequency reduces; the kinetic energy stored in rotating masses of the turbine-generator is transformed into electrical power used to supply the load, in a process referred to as inertial response.

As Figure 3-2 shows, the 1 GW production lost, is replaced by the inertial response immediately after the disturbance. As soon as the FCR begins to activate, or the load begins to diminish with decreasing frequency, the inertial response reduces.

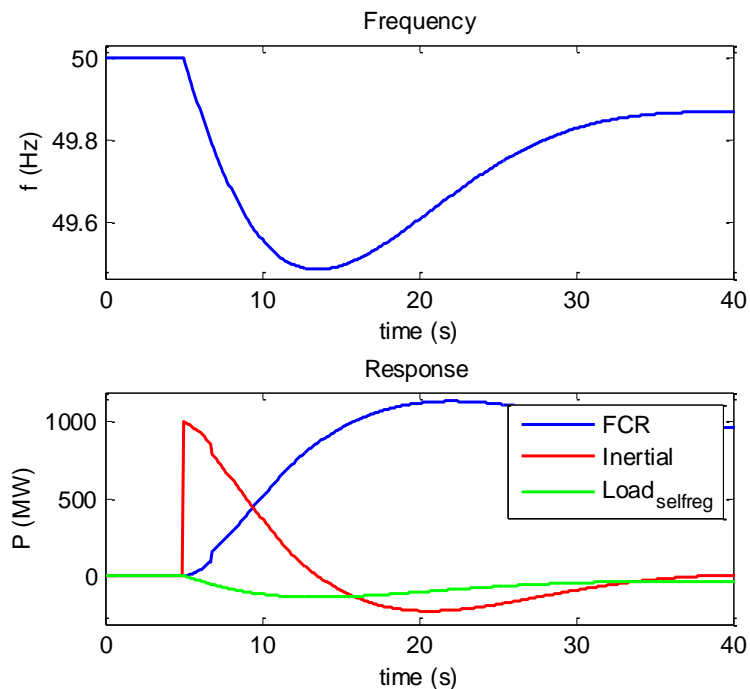


FIGURE 3-2 FREQUENCY, INERTIAL RESPONSE, RESPONSE FROM THE FREQUENCY-DEPENDENT LOAD, AND FREQUENCY CONTAINMENT RESERVES

Once the maximum instantaneous frequency deviation has been reached, synchronously-connected rotating machines begin to accelerate and inertial response changes from positive to negative. Once the mechanical power from the turbine is equal to the electrical power from the generator, the frequency stabilises again. At that point, the inertial response is zero.

Figure 3-3 illustrates how frequency behaves after a loss of production when the amount of kinetic energy in the system varies. The solid lines represent a situation where FCR begins to respond to the decreasing frequency and the dotted lines represent a situation without FCR.

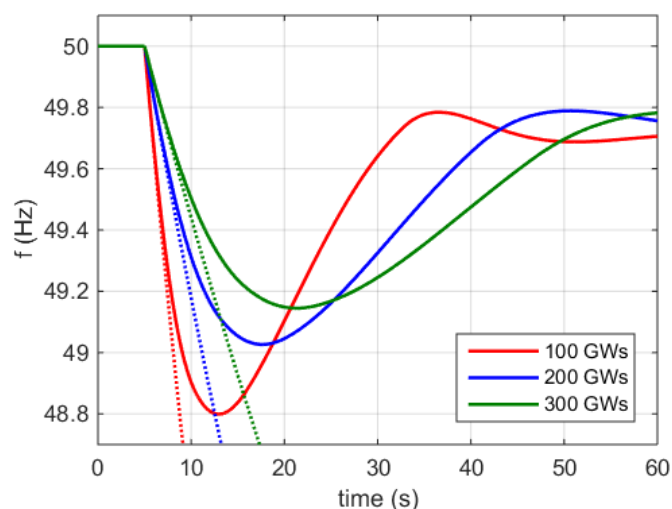


FIGURE 3-3 THE EFFECT OF THE AMOUNT OF KINETIC ENERGY ON THE BEHAVIOUR OF FREQUENCY AFTER A LOSS OF PRODUCTION WITH (SOLID) AND WITHOUT (DOTTED) FCR

Figure 3-3 shows that a higher kinetic energy in the system, results in a slower frequency decay and a higher minimum instantaneous frequency.

3.1.4 SYNTHETIC INERTIA

Since non-synchronously-connected production units, like modern wind turbine generators, are connected via power converters, their rotational speed is isolated from the system frequency. They therefore do not deliver a natural inertial response and do not contribute to the system inertia.

A controller which emulates the inertial response of a synchronously-connected generator can be included in a non-synchronously-connected production unit. Inertial response produced by such a controller is often referred to as a synthetic, emulated, artificial, or virtual inertial response. Using this kind of controller, it may be possible to (for example) extract kinetic energy from the blades and the rotor of a non-synchronously-connected wind turbine [6]. This can be achieved by measuring the rate of change of system frequency, and applying an appropriate electrical torque on the rotor of the wind turbine. This slows down the rotor, which in turn releases kinetic energy from the blades and the rotor in a similar fashion as a synchronous generator.

HVDC-links could also be controlled in such a way, that inertial response is transferred from one synchronous system to another [7].

3.1.5 FREQUENCY RESPONSE INDICATORS

In this report, frequency measurements from frequency disturbances have been collected and assessed in order to investigate relations to the inertia. A set of frequency response indicators is calculated for each frequency disturbance.

It is however important to note that the frequency is not the same throughout the whole system. During a disturbance the measurement location in the system plays a role due to the propagation of the frequency wave. In Figure 3-4 the measured frequency during a frequency disturbance in the Nordic power system at two locations is shown.

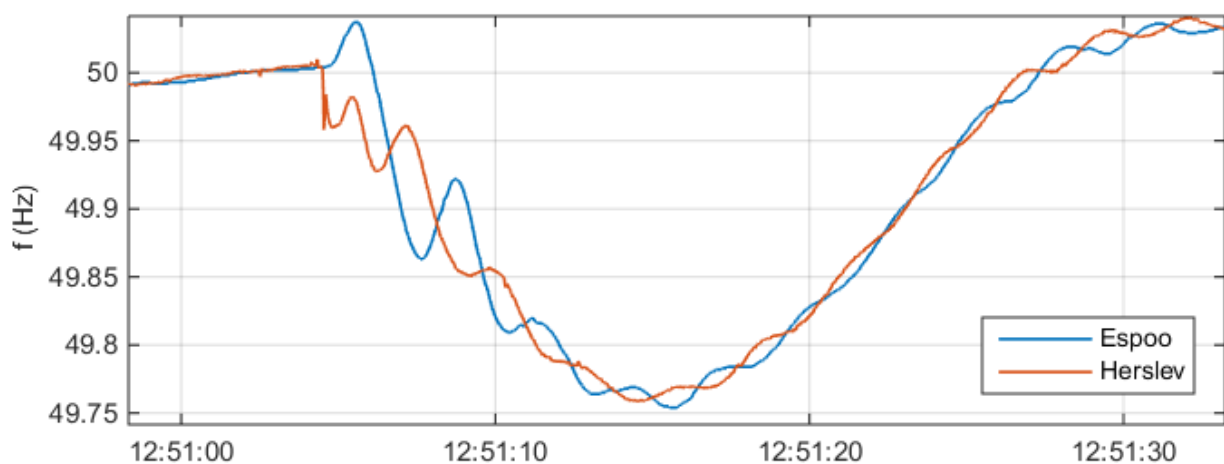


FIGURE 3-4 FREQUENCY IN ESPOO (SOUTHERN FINLAND) AND HERSLEV (DENMARK) AFTER A LOSS OF 580 MW

Inter-area oscillations, where generator groups oscillate against each other, can be seen in the figure.

When examining the frequency after a disturbance, there are features of interest which can affect a power system. Features such as the minimum instantaneous frequency, and the time to reach this minimum instantaneous frequency, can be used to describe the consequences of frequency disturbances, and are used in dimensioning various system parameters.

The frequency in the Nordic power system is measured by several Phasor Measurement Units (PMUs) or similar devices with a sample frequency of 10–100 Hz. Depending on the accuracy of the measurement, a filter has been used to reduce the level of measurement noise [2].

There are several indicators in relation to a frequency disturbance that should be defined. The start time of a disturbance, the frequency before the disturbance, the minimum or maximum instantaneous frequency, the maximum frequency deviation, and the time to reach the maximum instantaneous frequency deviation are shown in Figure 3-5, which provides a graphical representation of the different frequency response indicators for a disturbance.

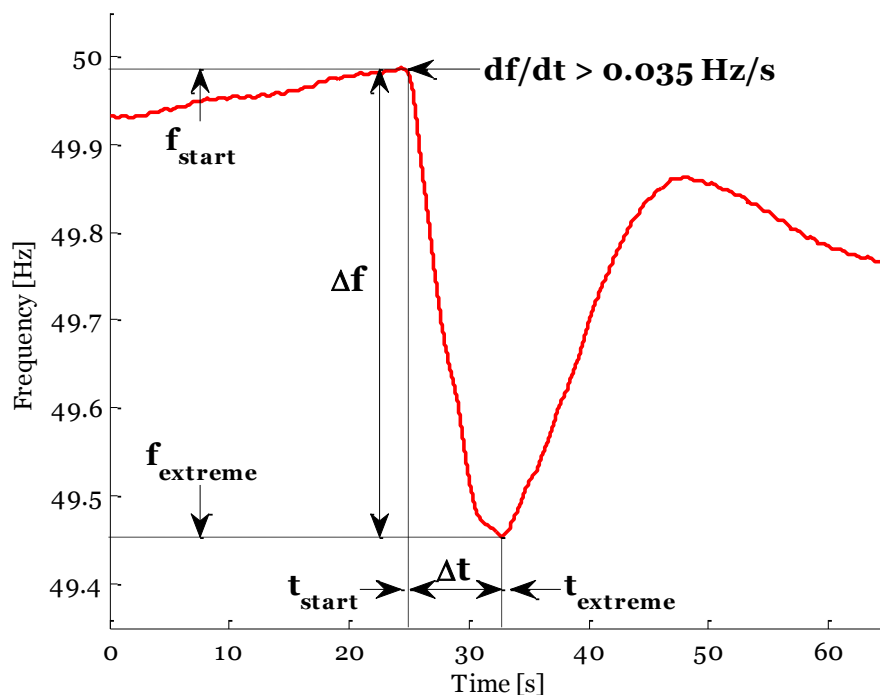


FIGURE 3-5 GRAPHICAL REPRESENTATION OF FREQUENCY RESPONSE INDICATORS

In this figure f is frequency and t is time.

Start of the disturbance

The start of the frequency disturbance, t_{start} , is defined as the time when the absolute value of the Rate of Change of Frequency (RoCoF), calculated from the filtered frequency, exceeds 0.035 Hz/s.

The value 0.035 Hz/s was chosen as a threshold after performing an empirical analysis. By using this threshold, the start time was found for all studied disturbances, and was not sensitive to the filtered measurement noise.

Minimum (maximum) instantaneous frequency

The minimum or maximum instantaneous frequency, f_{extreme} , is defined as the highest or lowest frequency during a disturbance, depending on if there was a loss of production or load. The time when the frequency reaches f_{extreme} is defined as t_{extreme} . For the disturbance in Figure 3-5 there is a loss of production and the minimum instantaneous frequency $f_{\text{extreme}} = 49.45$ Hz occurs at $t_{\text{extreme}} = 32.8$ s.

Maximum frequency deviation, and time to reach the maximum frequency deviation

The change in frequency, Δf , is defined as the difference between the minimum or maximum instantaneous frequency deviation and the frequency at the start of the disturbance.

$$\Delta f = |f_{\text{extreme}} - f_{\text{start}}| \quad (3.8)$$

In the same way the time to reach the maximum frequency deviation, Δt , is calculated.

$$\Delta t = t_{\text{extreme}} - t_{\text{start}} \quad (3.9)$$

For the disturbance in Figure 2.5, the change in frequency is $\Delta f = 0.53$ Hz and the time to reach the maximum frequency deviation is $\Delta t = 7.8$ s.

Steady-state frequency

The Nordic project "Frequency Quality 2" (FQ2) defined a proxy for the steady-state frequency, $f_{\text{steady state}}$, as the average frequency between 90 s and 150 s after the disturbance.

Steady-state frequency deviation

The steady-state frequency deviation, $\Delta f_{\text{steady state}}$, is defined as: the absolute value of frequency deviation after occurrence of an imbalance, once the system frequency has been stabilised.

Damping of frequency after disturbance

Instead of the traditional damping, the FQ2 project defined the damping as the amplitude ratio calculated with the step from the first to the second, and the second to the third peak. In formulas:

$$\eta = |(f_{\text{extreme3}} - f_{\text{extreme2}}) / (f_{\text{extreme2}} - f_{\text{extreme}})| \quad (3.10)$$

In which (see also Figure 3-6),

f_{extreme2} : frequency of the second peak;

f_{extreme3} : frequency of the third peak.

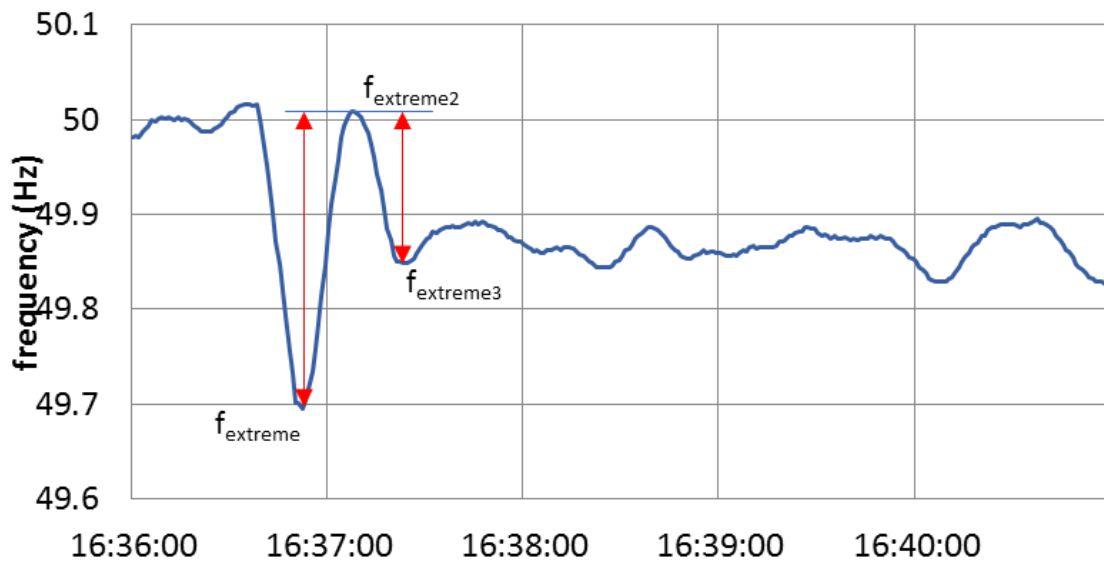


FIGURE 3-6 ILLUSTRATION OF THE VARIOUS FREQUENCY PEAKS FOR DETERMINING THE DAMPING

Frequency Bias Factor (FBF)

The frequency bias factor (regulating strength, $FBF = R_{FCR}$) can be calculated by:

$$FBF = \frac{\Delta P}{\Delta f_{\text{steady state}}} \quad (3.11)$$

where ΔP is the activated power change in steady state, and $\Delta f_{\text{steady state}}$ is the steady-state frequency deviation.

Background information of the disturbance

The following background information may be useful when archiving / studying a disturbance:

- *date and time*: time t_{start} in Central European Time (CET);
- *cause*: reason of the disturbance;
- ΔP : instantaneous imbalance caused by the disturbance: best estimate of the change in generation, load, or HVDC flow, taking into account the load of auxiliaries;
- E_k : inertia just before the incident, as estimated by the Nordic TSOs.

Frequency report of a disturbance

Figure 3-7 and Table 3-1 below provide an example of a frequency report of a disturbance that includes all the parameters described in this section. It is based on the reports in Fingrid's 'Frequency quality analysis' [8].

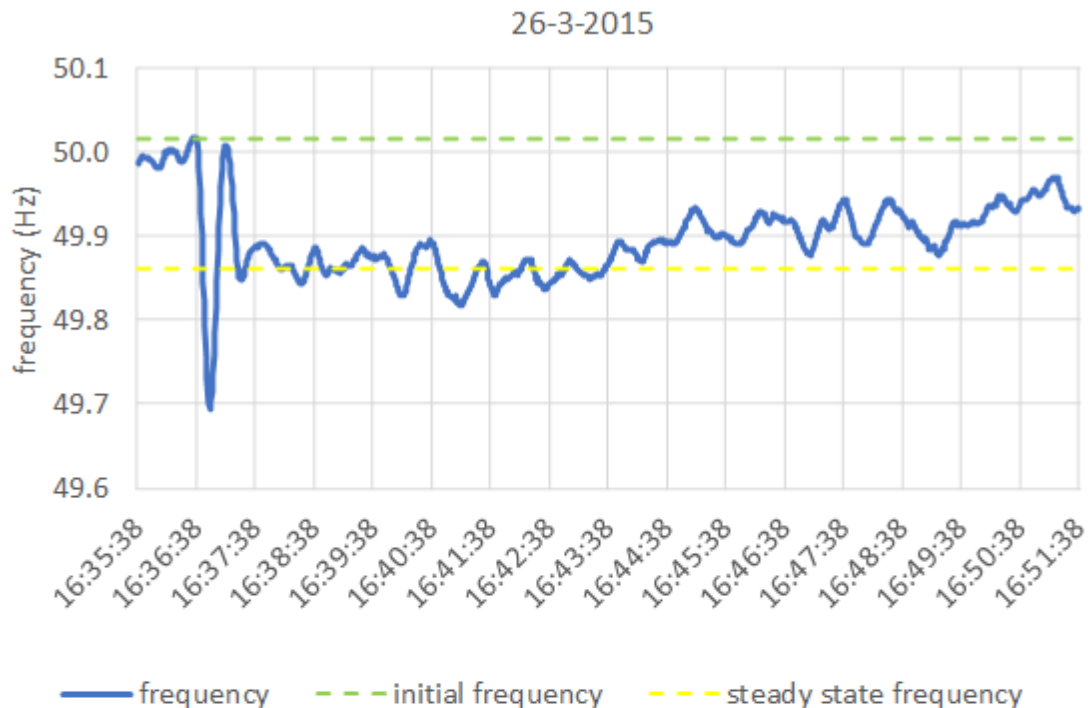


FIGURE 3-7 FREQUENCY DISTURBANCE REGISTRATION (26-3-2015)

TABLE 3-1 FREQUENCY DISTURBANCE INDICATORS (26-3-2015)

| | | | |
|---------------------------|----------------------------------|----------------------------------|-------------|
| Date (dd-mm-yyyy) | 26-03-2015 | Time (hh:mm:ss) | 16:36:38 |
| f_{start} | 50.016 Hz | f_{extreme} | 49.694 Hz |
| Δf | -0.322 Hz | Δt | 14.0 s |
| $f_{\text{steady state}}$ | 49.862 Hz | $\Delta f_{\text{steady state}}$ | 0.154 Hz |
| f_{extreme2} | 50.008 Hz | | |
| f_{extreme3} | 49.849 Hz | η | 51 % |
| ΔP | 990 MW | | |
| E_k | GWs ¹ | FBF | 6 417 MW/Hz |
| Cause | Loss of Forsmark 1 nuclear plant | | |

3.2 STABILITY WITH RESPECT TO REGULATING STRENGTH

In control theory, the term feedback is used to refer to a situation in which two (or more) dynamical systems are connected together such that each system influences the other and their dynamics are thus strongly coupled. The reason for using feedback systems is that the behaviour

¹ Inertia values are available as of April 1, 2015

over time of the system to be controlled is not known exactly. The feedback is then used to improve the behaviour of the system, based on measuring one or several signals on which the control actions are based. Feedback has potential disadvantages; if applied incorrectly, it can introduce instability. Frequency control in power systems is a feedback system where the power plant (power system) is affected by disturbances (net power variation), and the controller (primary control etc.) acts on measured frequency deviation with negative feedback. The purpose of negative feedback is to reduce the disturbance, by producing a control signal fed in to the system with an opposite sign to reduce the effect of the disturbance. Ideally it should cancel out the effect in the measured output (being the frequency deviation in the case of balancing power systems).

One important parameter in this respect, is the regulating strength which may have a significant impact on the stability in the system. The term regulating strength is equivalent to frequency bias factor (FBF), and is the activated steady-state power change divided by the frequency change. In terms of frequency stability, an increased regulating strength reduces the frequency deviation in the first frequency swing. It also decreases the steady-state frequency deviation. However, in terms of stability, viewed as closed-loop stability, an increased regulating strength may reduce the stability margin and the system may potentially become unstable at a too high regulating strength.

The driving force towards instability can be unwanted dynamics that may be part of the response of the primary reserves. Dynamics cause a phase shift, seen as a delay in the response, between the input and output signal. In combination with a high amplification of the signal it is then a driving force towards instability. The inertia in the system resists frequency to change, but in turn causes a phase shift; meaning, it takes some time before a frequency deviation is seen by the controller. The deviation has to become large enough so that the controller can counteract by adjusting its control signal. If the controller reacts without delay, and in proportion to the frequency deviation (ideal proportional primary frequency control), it will in principle not cause closed-loop instability due to increased regulating strength. However, when the controller possesses dynamics, a too high regulating strength makes the controller respond too much. The delay in the response, seen in the controlled power output as well as in the frequency (output), can make the controller to react such that its response, instead of being in phase with the output, amplifies it. Thus, the frequency deviation may oscillate with growing amplitude and thereby become unstable. By looking at stability as a linear closed loop, one may use a Nyquist diagram to explain the reasons behind, and elaborate on, the impact from increased regulating strength. The maximum regulating strength is a function of the kinetic energy in the system.

3.2.1 THE CONTROL PERSPECTIVE

Figure 3-8 shows a single-input single-output (SISO) system where $F(s)$ represents the dynamics of the control process, $G(s)$ the power plant, d is a disturbance signal entering the system, y is the output of the closed loop system, and s is the Laplace operator. Thus the blocks describe the dynamic behaviour of the control response and system by means of transfer functions.

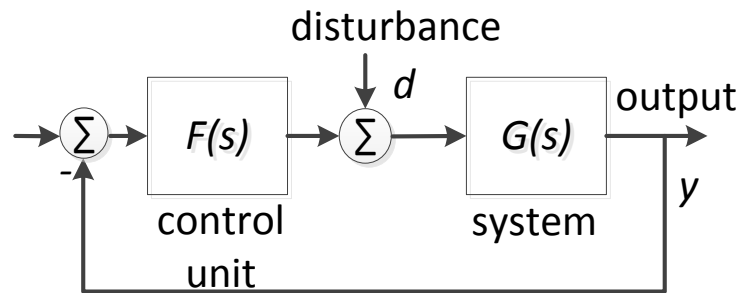


FIGURE 3-8 OVERVIEW OF A FEEDBACK SYSTEM

Using a lumped model of the system allows us to analyse stability in a SISO system. The aim is to determine whether or not the closed-loop system is stable. The mathematical framework of transfer functions provides an elegant method, which is called *loop analysis*. The basic idea of loop analysis is to trace how a sinusoidal signal propagates in the feedback loop, this by investigating if the propagated signal grows or decays.

To cause instability, the output signal has to be in phase with the loop signal and the gain has to be greater than one. With a lumped model, the system has a phase shift starting at 0° which is going towards 90° as the complex angular frequency increases. As negative feedback is used, the gain at 180° phase shift of the loop signal is a concern when considering stability. If the phase shift of the control unit never exceeds 90° phase shift, e.g. proportional control (negligible dynamics), the loop signal will not turn out to be in phase with the output, and does not cause instability due to feedback. With non-negligible dynamics, the phase shift may become 180° and thereby analysis of stability is of importance. One way to analyse stability is by using the Nyquist criterion which in turn uses the loop gain. The loop gain is defined as

$$G_0(s) = F(s)G(s) \quad (3.12)$$

The loop transfer function, also named sensitivity, is defined as

$$S(s) = \frac{1}{1 + G_0(s)} \quad (3.13)$$

and describes the propagation of a signal through the loop i.e. how the output amplifies through the loop.

The amplification of a signal is determined by the denominator. Whether the signal grows, when it is phase shifted by 180° (the signal has an opposite sign), determines if the system is stable or not. The point where a signal has a 180° phase shift, and its amplitude remains (gain equal to one), corresponds to where the denominator is equal to zero i.e.

$$G_0(s)|_{s=j\omega_0} = -1 \quad (3.14)$$

In such conditions, the signal grows to infinity. As such, the point $-1+0j$ is therefore of interest in relation to the curve of the loop gain.

The Nyquist curve is the loop gain, that can be plotted in the complex plane, with the Laplace operator s replaced by the complex value $j\omega$, and ω varying as shown in Figure 3-9. The system is

asymptotically stable if the Nyquist curve does not encircle the point $-1+0j$. Basically, at the point where the Nyquist curve has a phase shift of 180° , the loop transfer function should be smaller than one. For a more detailed description readers are referred to textbooks in the field of linear control theory. In practice it is not enough that a system is stable. There should also be some margins of stability that would describe how stable the system is, and its robustness to perturbations. A stability margin is depicted in Figure 3-9, as a distance r between the Nyquist curve and the point $-1+0j$. It can be specified in terms of an amplitude margin² (also known as gain margin, A_m), a phase margin³ (φ_m), and the smallest Euclidian distance r , between the curve and the point -1 (referred to as the stability margin).

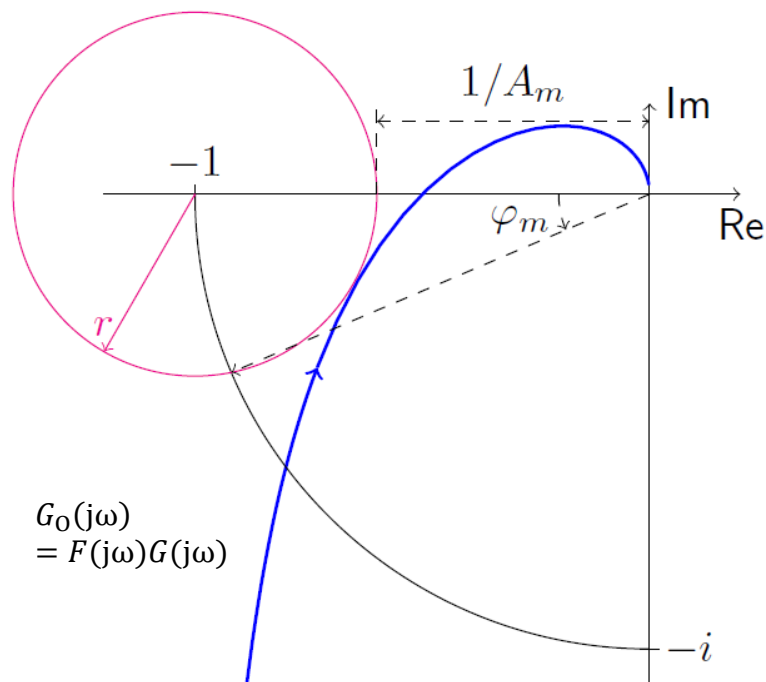


FIGURE 3-9 NYQUIST DIAGRAM.

THE BLUE CURVE IS THE LOOP GAIN OF THE CLOSED LOOP SYSTEM AND THE CIRCLE REPRESENTS A STABILITY MARGIN.

The loop gain is given by

$$G_O(j\omega) = F(j\omega)G(j\omega) = R_{FCR}F_O(j\omega)G(j\omega) = R_{FCR}F_O(j\omega) \frac{f_n/S_n}{2H_{sys}j\omega + kf_n} \quad (3.15)$$

where $F_O(j\omega)$ is the transfer function of the FCR-D with gain one at steady state. H_{sys} is the total inertia of the system, $j\omega$ is the complex angular frequency, and f_n is the nominal frequency. R_{FCR} is the continuously-controlled regulating strength.

² The number of times the loop gain can be amplified until the Nyquist curve intersects with the point -1 .

³ The angle between the negative real axis and the point where the curve crosses a circle centred in the origin with a unity radius.

Figure 3-10 exemplifies the time response of two systems, one that is stable and another that is unstable. The difference between the responses is the regulating strength which, in the unstable case, is too high. Figure 3-11 shows the corresponding Nyquist curves of the two loop gains. Clearly, the curve of the unstable system crosses the real axis to the left of the point $-1+j\cdot 0$. Thereby it encloses this point and stability cannot be ensured.

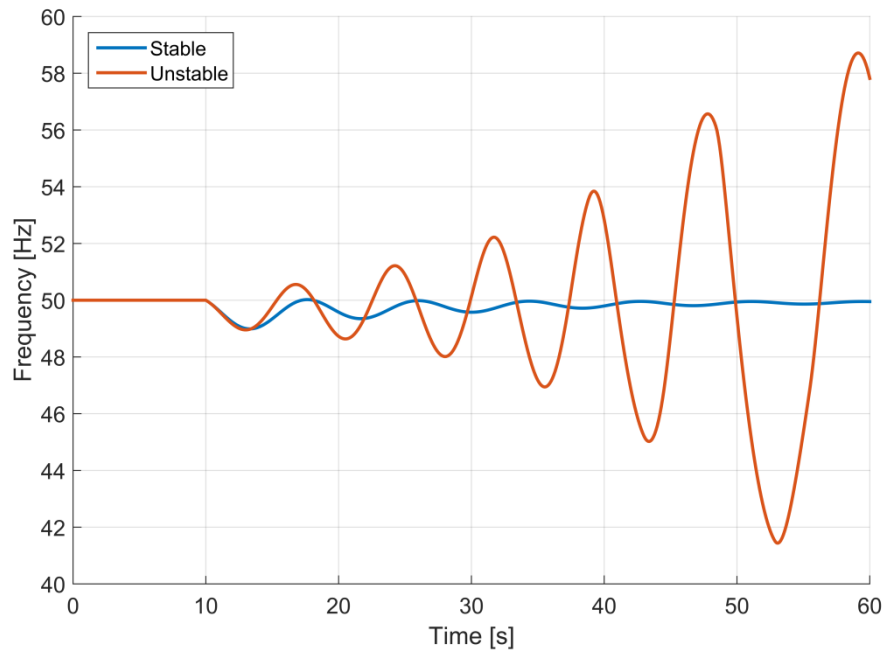


FIGURE 3-10 ILLUSTRATION OF A STABLE AND AN UNSTABLE RESPONSE

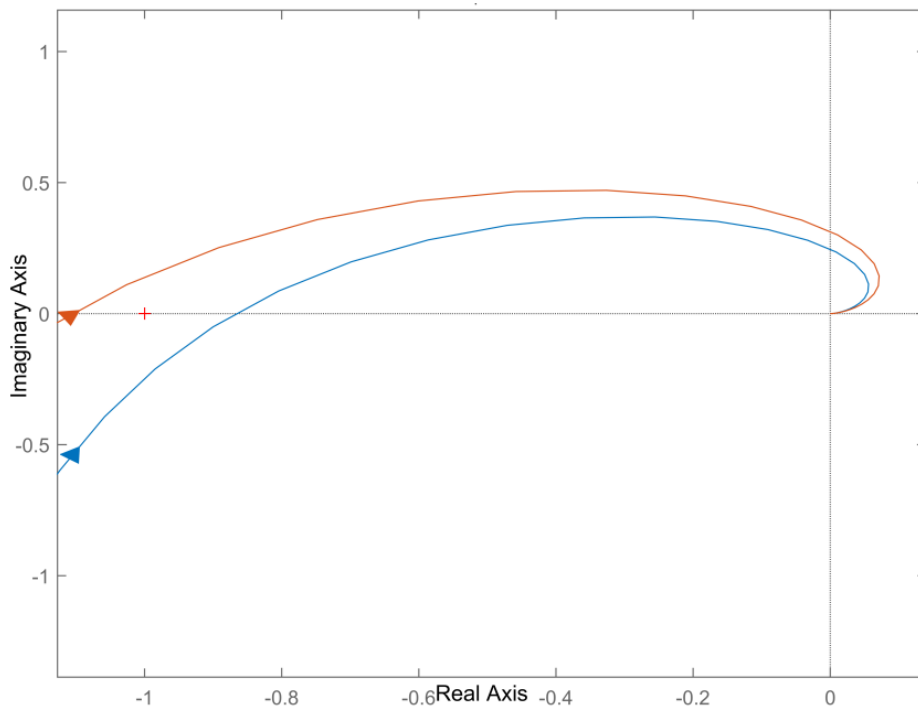


FIGURE 3-11 NYQUIST CURVE FOR A STABLE AND AN UNSTABLE SYSTEM

If the FCR-D is designed to keep certain stability margins at a minimum inertia level in the system for a maximum regulating strength, a reduced inertia (below this minimum level) implies that the regulating strength should be adjusted accordingly. Thus, when the inertia goes below this minimum level, the regulating strength has to be reduced as well to ensure the stability margin. In the project Revision of the Frequency Containment Process (FCP), a stability margin is introduced for a minimum kinetic energy of 120 GWs in the system. For FCR-N the regulating strength is

$$R_{\text{FCR-N}} = \frac{600 \text{ MW}}{0.1 \text{ Hz}} = 6\,000 \text{ MW/Hz} \quad (3.16)$$

as the current volume of 600 MW FCR-N is procured. For FCR-D a scaling factor [9] can be introduced, however, the equivalent regulating strength is equal to

$$R_{\text{FCR-D}} = \frac{1\,450 \text{ MW}}{0.4 \text{ Hz}} = 3\,625 \text{ MW/Hz} \quad (3.17)$$

assuming the procured volume to be 1 450 MW.

Two analyses are performed,

- the first (Section 3.2.2) assesses how the regulating strength of the FCR-D (or FCR-N) should be changed when the kinetic energy decreases below 120 GWs (low-inertia system)
- the second (Section 3.2.3) determines the maximum regulating strength for which closed-loop stability is maintained in the low-inertia system. An example is given for FCR-D.

3.2.2 REDUCED REGULATING STRENGTH FOR KINETIC ENERGY BELOW 120 GWs

From (3.15), the loop gain, it is assumed that the Nyquist curve is exactly at the stability circle at any point and further that it enters the circle if the regulating strength is increased⁴. Then to ensure stability, the ratio between R and H has to stay the same or below the original value to ensure robust stability. For example, if the inertia is reduced to 90 % from the value of the minimum system, a reduction of regulating strength to 90 % guarantees robust stability. Note that, to maintain the stability margin after the dimensioning incident, the loss of kinetic energy in the system due to the disconnections has to be subtracted from the total kinetic energy before the incident. If the kinetic energy is reduced from 120 GWs to a value of X , the regulating strength has to be reduced accordingly to maintain the stability margin:

$$R_{\text{FCR-D-red}} = \left(1 - \frac{120 \text{ GWs} - X}{120 \text{ GWs}}\right) R_{\text{FCR-D}} \quad (3.18)$$

An equivalent analysis can be used for FCR-N. One can argue that the stochastic net power variations are likely to reduce as inertia is reduced since the loading of the system is low. On the other hand, low-inertia situations are likely to occur when there is much wind (and solar) power

⁴ For the sake of clarity, the assumption implies not to have the Nyquist curve lying at the bottom of the stability circle since increase in the regulating strength will lead to that point moves in to the circle.

production in the system, which may in turn increase the net power variations. Therefore, one may have to look at new reserves for the normal operation frequency band as well when the kinetic energy goes below the critical value.

3.2.3 MAXIMUM CONTINUOUSLY-CONTROLLED REGULATING STRENGTH FOR FCR-D

The Revision of the Frequency Containment Process (FCP) project has developed stability requirements for a maximum regulating strength in a 120 GWs kinetic energy system [9]. The stability requirements allow for uncertainty in the model or control response (i.e. robust stability); one such uncertainty being the regulating strength. To exemplify the robustness, the potential increase of the regulating strength will be assessed before the stability margin is compromised. Stability requires the point $-1+0\cdot j$ not be encircled. Therefore, consider the loop point that has a 180° phase shift ($F(j\omega_1)\cdot G(j\omega_1) = -1$), pointing in the negative direction along the real axis. Assume the point to lie just at the circle of the stability margin, i.e. the coordinate is $0\cdot j + (r-1)$. Then, the loop gain can be written as a function of the regulating strength:

$$G_O|_{\omega_1} = F(j\omega_1)G(j\omega_1) = \frac{(R_{\text{FCR-D}} + \Delta R)}{R_{\text{FCR-D}}} (1 - r)e^{j\pi} \quad (3.19)$$

where $R_{\text{FCR-D}} = 3\,625$ MW/Hz is the regulating strength used in the design, and ΔR is the additional regulating strength. Thus, the total regulating strength becomes $R_{\text{FCR-D}} + \Delta R$. Note that this quantifies the margin and is not suggested as a mitigation measure.

The stability margin is specified to be $r = 0.43$ [9]. The regulating strength, according to (3.19), then becomes

$$\frac{(3\,625 \text{ MW/Hz} + \Delta R)}{3\,625 \text{ MW/Hz}} (1 - r)e^{j\pi} > -1 \quad (3.20)$$

$\Delta R < 2\,734$ MW/Hz and it follows that the total regulating strength should be less than

$$R_{\text{FCR-D}} + \Delta R = 3\,625 \text{ MW/Hz} + 2\,734 \text{ MW/Hz} = 6\,359 \text{ MW/Hz} \quad (3.21)$$

In other words, additional FCR-D may be procured (up to 1 094 MW additional, being $0.4 \text{ Hz} \cdot R_{\text{FCR-D}} = 0.4 \text{ Hz} \cdot 6\,359 \text{ MW/Hz} = 2\,544 \text{ MW} = 1\,450 \text{ MW} + 1\,094 \text{ MW}$).

Note that the stability margin for the closed loop linear system is zero with this design, volume, and kinetic energy. In addition, the frequency will oscillate and the response quality may be poor, but stability is ensured. Also note that any uncertainty may drive the closed loop system to become unstable. Based on the work and experience in the FCP project, it is likely that there is additional distance from the point where the Nyquist curve crosses the real axis and the stability circle (and therefore also to the point $-1+0\cdot j$). Thus, similar to what is illustrated in Figure 3-9, the Nyquist curve tends to cross the real axis with some margin to the stability circle.

To conclude: since robust stability is applied, there is headroom for some additional FCR-D (up to 1 094 MW, but results in zero stability margin) as the allowed uncertainty. However, additional regulating strength may violate the margin to stability which reduces the headroom for other uncertainties. Therefore, procuring additional FCR-D may not be preferred if stability margins are

to be kept. In addition, if the kinetic energy reduces below 120 GWs, what the robust stability is dimensioned for, the continuously-controlled regulating strength should be reduced in proportion to that reduction.

3.3 SIMULATION MODEL TO ASSESS THE LOW-KINETIC ENERGY MITIGATION MEASURES

The simulation model that is used to assess the low-kinetic energy mitigation measures, the tuning of the model parameters, and the model validation, are elaborated upon in the following sections.

3.3.1 SIMULATION MODEL: DESCRIPTION

The power system consists of generation and consumption interconnected by the grid. Thus the inertia and frequency control are distributed throughout the grid. The modelling of the power system, FCR providing units, Emergency Power Control (EPC) from HVDC links, and Fast Frequency Reserve (FFR) is performed using a one-machine equivalent; assumptions for this are given below.

Studies are performed using a one-machine equivalent for the sake of simplicity. For the same reason, and to enable efficient use of linear analysis, power system components like power lines, transformers etc. are omitted. Furthermore, voltage dynamics are also omitted (automatic voltage regulators on generators, load voltage characteristics etc.). Figure 3-12 shows an overview block diagram of the simulation model. FCR-D is modelled as a hydro power unit as it is the most common source for FCR-D in the Nordic power system, though other sources of FCR-D do exist. FFR is further explained in Chapter 6, while EPC (that - in the remainder of this report - is only related to activation based on frequency deviation) is further explained in Section 3.3.2 and Chapter 7.

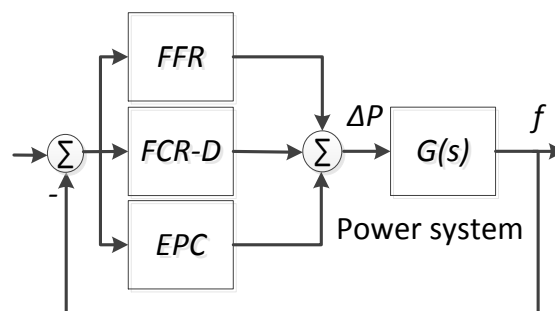


FIGURE 3-12 OVERVIEW BLOCK DIAGRAM OF THE SIMULATION MODEL

SIMULATION MODEL: HYDRO POWER UNIT MODEL

The hydro power unit model consists of a PID-type turbine governor with gate droop, gate servo, and the hydraulic system (penstock and turbine), as illustrated in Figure 3-13.

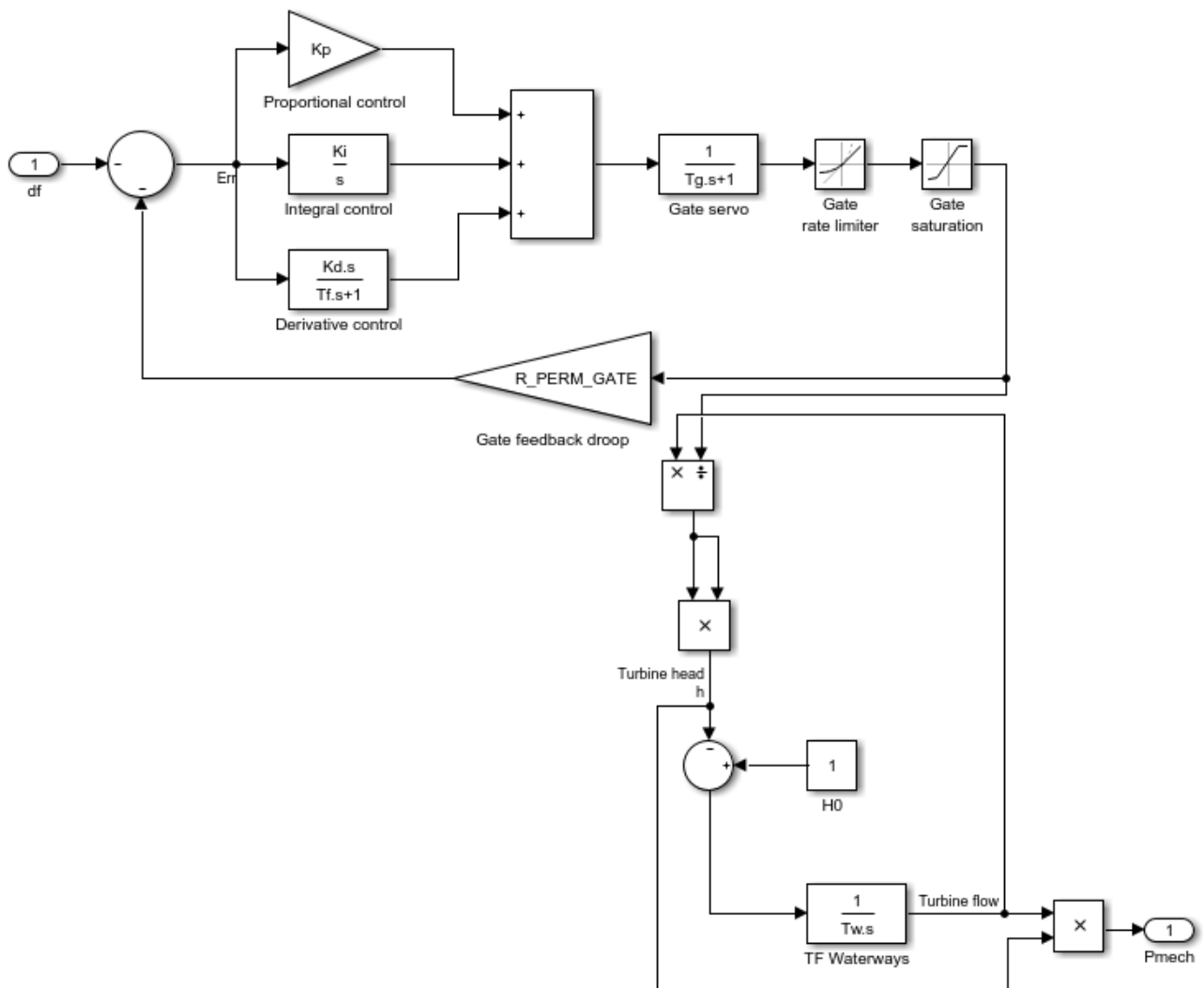


FIGURE 3-13 BLOCK DIAGRAM REPRESENTATION OF THE HYDRO UNIT MODEL

The PID governor has a parallel structure with proportional, integral and derivate control blocks. The derivate control block is equipped with a filter, which is used to reduce measurement noise. The gate servo model includes ramp rate limits for the servo and servo saturation. Penstock is represented using an inelastic water column model and the turbine is represented using a generic turbine model [10, p. 55]. Together these form a non-linear representation of the hydraulic system. Fixed parameters used are listed in Table 3-2. The parameters used are based on feedback received from hydro producers and experts working in the field, and can be considered as typical values for a large population of the existing units.

TABLE 3-2 HYDRO UNIT PARAMETERS

| Parameter | Value | Description |
|-------------|-------------|--|
| T_f | 0.15 (s) | Filter time constant for derivate part |
| T_g | 0.2 (s) | Gate servo time constant |
| R_{open} | 0.1 (pu/s) | Gate servo ramp-rate limit for opening |
| R_{close} | -0.1 (pu/s) | Gate servo ramp-rate limit for closing |
| G_{max} | 1.0 (pu) | Gate saturation upper limit |
| G_{min} | 0.0 (pu) | Gate saturation lower limit |

The hydro unit model described is very general which means that it is not well suited for in-depth simulations of specific hydro units. On the other hand, the model captures general dynamics of different turbine types. The model does not include, for example, servo positioning loops, dynamics of double-regulated turbines (Kaplan turbines), turbine self-regulation etc.

3.3.2 SIMULATION MODEL: TUNING OF THE PARAMETERS

In order to make the simulation model represent the current power system, a tuning of the model parameters is necessary. The simulated frequency from the model is compared to the measured frequency in the real power system. Four disturbances, in the period of 2015-07-01 until 2016-10-01, were chosen for tuning the model (see Table 3-3). All disturbances reflect a disconnection of generation, and were selected based on their power imbalance, such to represent a severe incident. Disturbances indicating that the loss of power was not instantaneous, but gradually reduced over time, were excluded. The kinetic energy in the system at the time of the disturbance was collected from the estimation tool implemented in the Nordic SCADA systems [2]. It is assumed that this estimation does not represent the full kinetic energy in the system, and therefore the kinetic energy used in the tuning process has been increased by 20 %. Disturbance-specific parameters are presented in the table.

TABLE 3-3 TUNING DISTURBANCES AND PARAMETERS

| Disturbance | Date & Time | Power imbalance [MW] | Estimated kinetic energy ⁵ [GWs] | System load [GW] |
|-------------|---------------------|----------------------|---|------------------|
| 1 | 2015-08-27 10:15:01 | -1 100 | 229 | 39.4 |
| 2 | 2015-11-10 09:30:32 | -1 100 | 265 | 46.8 |
| 3 | 2016-06-20 16:10:13 | -840 | 210 | 37.3 |
| 4 | 2016-07-04 13:41:06 | -1 000 | 230 | 37.6 |

⁵ The value includes a 20 % add-on

In the simulation model, the EPC of HVDC links is included using the actual settings. EPC is activated when the measured frequency is outside the trigger level during the delay time. When the EPC is activated, and there is available capacity, the power flow on the HVDC link will change to support the power system. If the HVDC link is using all capacity for import there is no room for EPC activation. Most HVDC links have several frequency levels where the settings change. All existing EPCs are modelled according to their actual settings of capacity, ramp rate, frequency trigger, and delay, as listed in Table 3-4.

TABLE 3-4 EMERGENCY POWER CONTROL SETTINGS IMPLEMENTED IN THE SIMULATION MODEL (UNDER-FREQUENCY SETTINGS ONLY)

| HVDC link | Step | Frequency trigger [Hz] | Capacity [MW] | Ramp rate [MW/s] | Time delay [s] |
|------------------------------------|------|------------------------|---------------|------------------|----------------|
| Kontiskan 2 | 1 | 49.8 | 150 | 20 | 0.3 |
| | 2 | 49.6 | 150 | 50 | 0.1 |
| | 3 | 49.5 | 150 | 200 | 0.05 |
| Baltic Cable | 1 | 49.55 | 150 | 100 | 0.5 |
| | 2 | 49.2 | 300 | 100 | 0.5 |
| SwePol | 1 | 49.4 | 150 | 100 | 0.5 |
| | 2 | 49.1 | 300 | 100 | 0.5 |
| Great Belt | 1 | 49.5 | 18 | 10 | 0.5 |
| Skagerrak 1+2 (combined values) | 1 | 49.3 | 140 | 20 | 0.06 |
| | 2 | 49.0 | 120 | 60 | 0.06 |
| Skagerrak 3+4 (combined values) | 1 | 49.3 | 130 | 10 | 0.06 |
| | 2 | 49.0 | 120 | 50 | 0.06 |
| Kontek | 1 | 49.5 | 50 | 10 | 0.5 |
| NordBalt | 1 | 49.4 | 150 | 990 | 0.5 |
| | 2 | 49.1 | 300 | 990 | 0.5 |

The activated EPC capacity of the HVDC links, at the time of the four disturbances, is shown in Table 3-5.

TABLE 3-5 ACTIVATED EPC CAPACITY AT THE TIME OF THE FOUR TUNING DISTURBANCES

| HVDC link | Activated capacity [MW] | Activated capacity [MW] | Activated capacity [MW] | Activated capacity [MW] |
|--------------|-------------------------|-------------------------|-------------------------|-------------------------|
| | Disturbance 1 | Disturbance 2 | Disturbance 3 | Disturbance 4 |
| Kontiskan 2 | 150 | 0 | 0 | 2.5 |
| Baltic Cable | 150 | 0 | 0 | 2 |

A major part of the FCR-D hydro unit model parameters were varied for all disturbances. Table 3-6 presents the parameter ranges used in the sweeps. In total, around 60 000 parameter sets have been simulated. The ranges are based on initial test simulations for a one-machine model to represent the system. Some of the parameters might differ from what is normally used for a single generator.

TABLE 3-6 SWEEPING PARAMETERS DURING THE TUNING

| Parameters | Range |
|----------------------------------|-------------|
| Proportional gain K_p | 1–10 |
| Integral gain K_i | 0.1–5 |
| Derivative gain K_d | 0–1 |
| Droop ⁶ [%] | 1–3 |
| Water time constant T_w [s] | 0.8–1.2 |
| Unit loading [%] | 40–80 |
| FCR-D capacity [MW] | 1 500–1 700 |

For each parameter set, the simulated frequency was compared to the measured one for all four disturbances. The set with the smallest deviation, tabulated in Table 3-7, represents the system behaviour in the best way. The frequency simulated with the model by using these parameters is compared to the measured frequency in Figure 3-14, Figure 3-15, Figure 3-16, and Figure 3-17.

TABLE 3-7 THE PARAMETER SET BEST REPRESENTING THE FOUR CHOSEN DISTURBANCES

| Parameters | Range |
|----------------------------|-------|
| Proportional gain K_p | 4 |
| Integral gain K_i | 2 |
| Derivative gain K_d | 1 |
| Droop ⁶ [%] | 2 |

⁶ Referred to as “R_PERM_GATE” in Figure 3-13

| | |
|----------------------------------|-------|
| Water time constant T_w [s] | 0.8 |
| Unit loading [%] | 80 |
| FCR-D capacity [MW] | 1 600 |

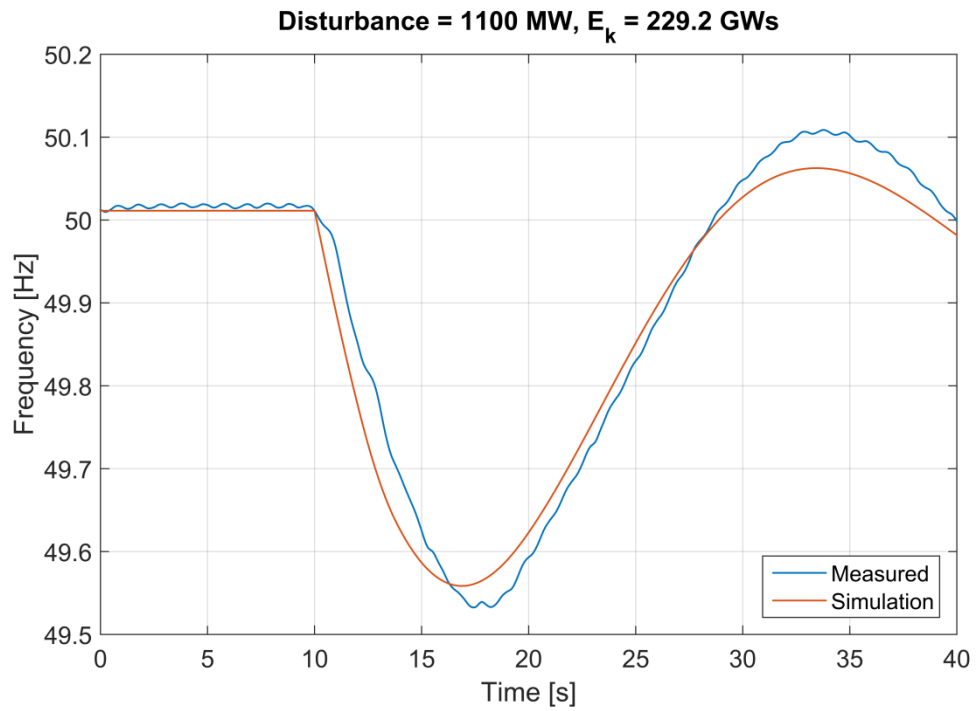


FIGURE 3-14 TUNING DISTURBANCE 1

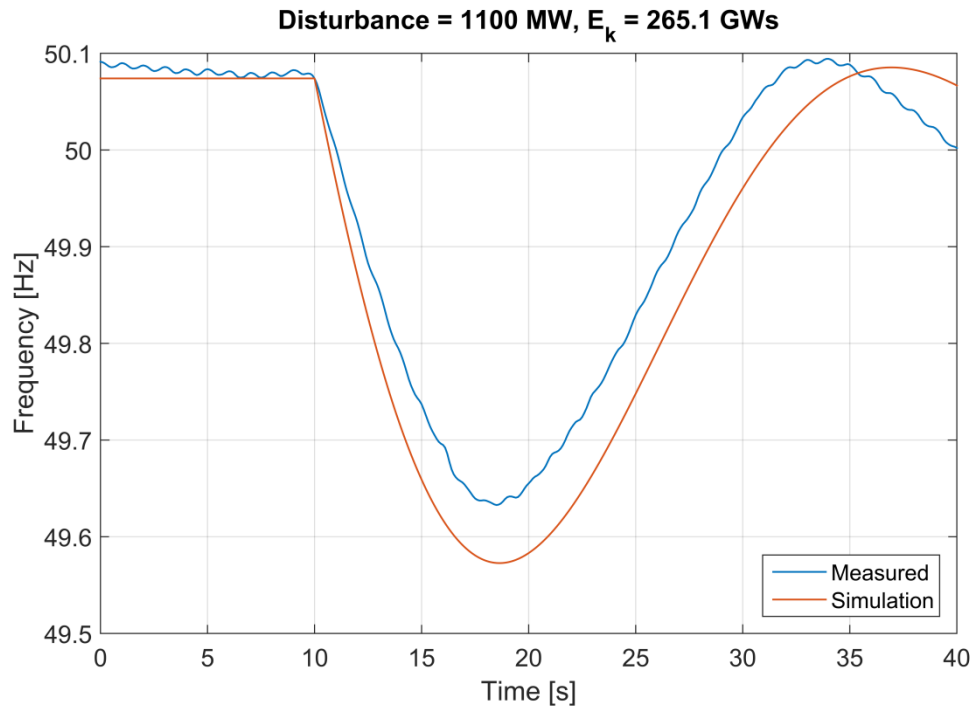


FIGURE 3-15 TUNING DISTURBANCE 2

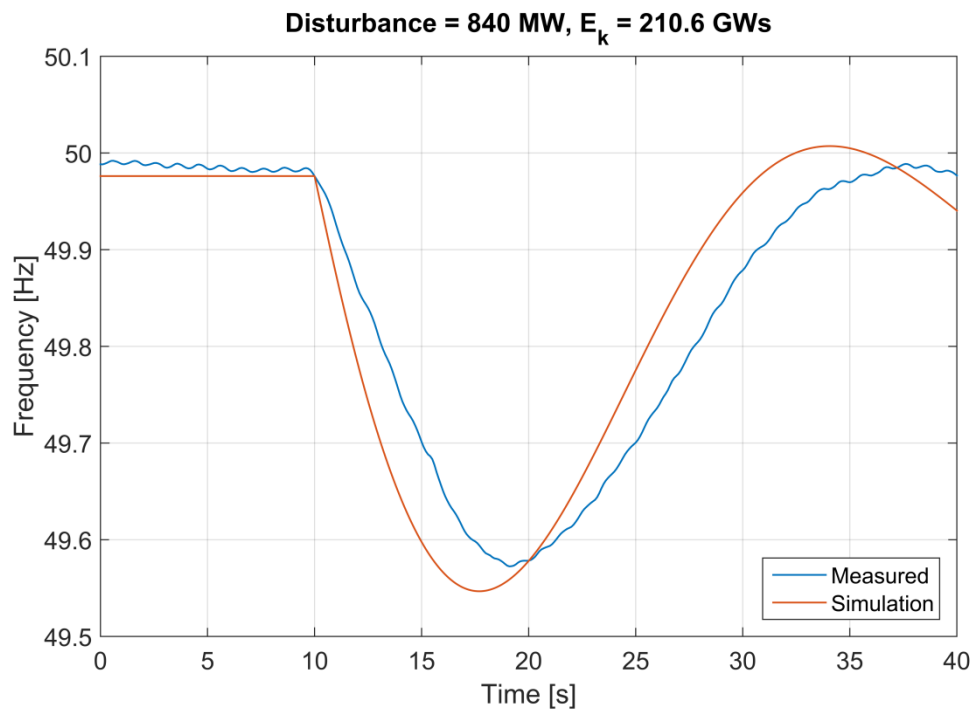


FIGURE 3-16 TUNING DISTURBANCE 3

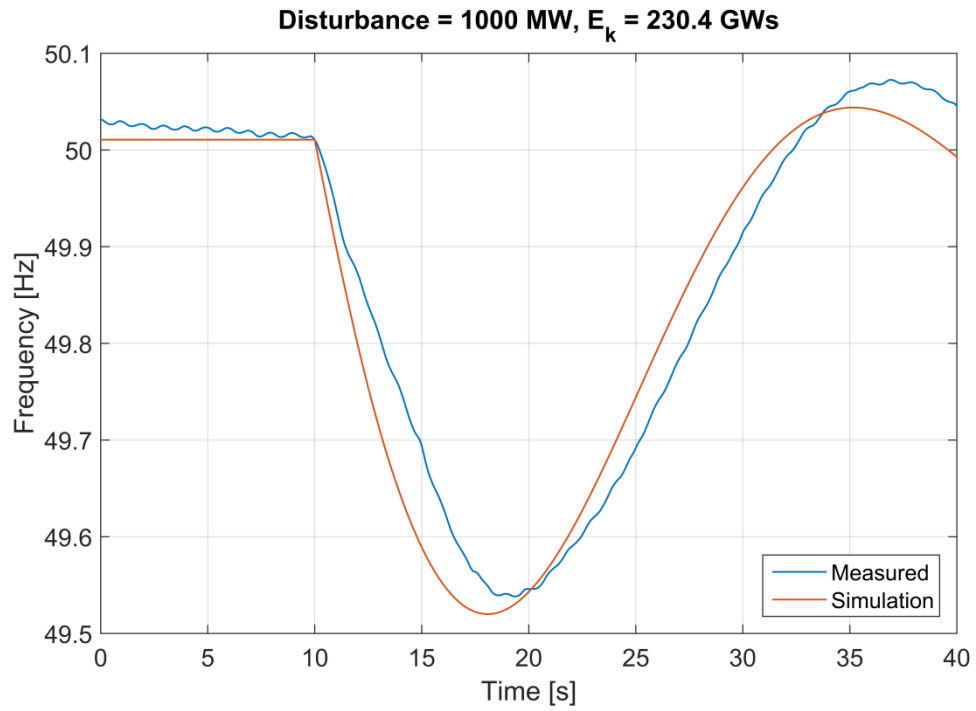


FIGURE 3-17 TUNING DISTURBANCE 4

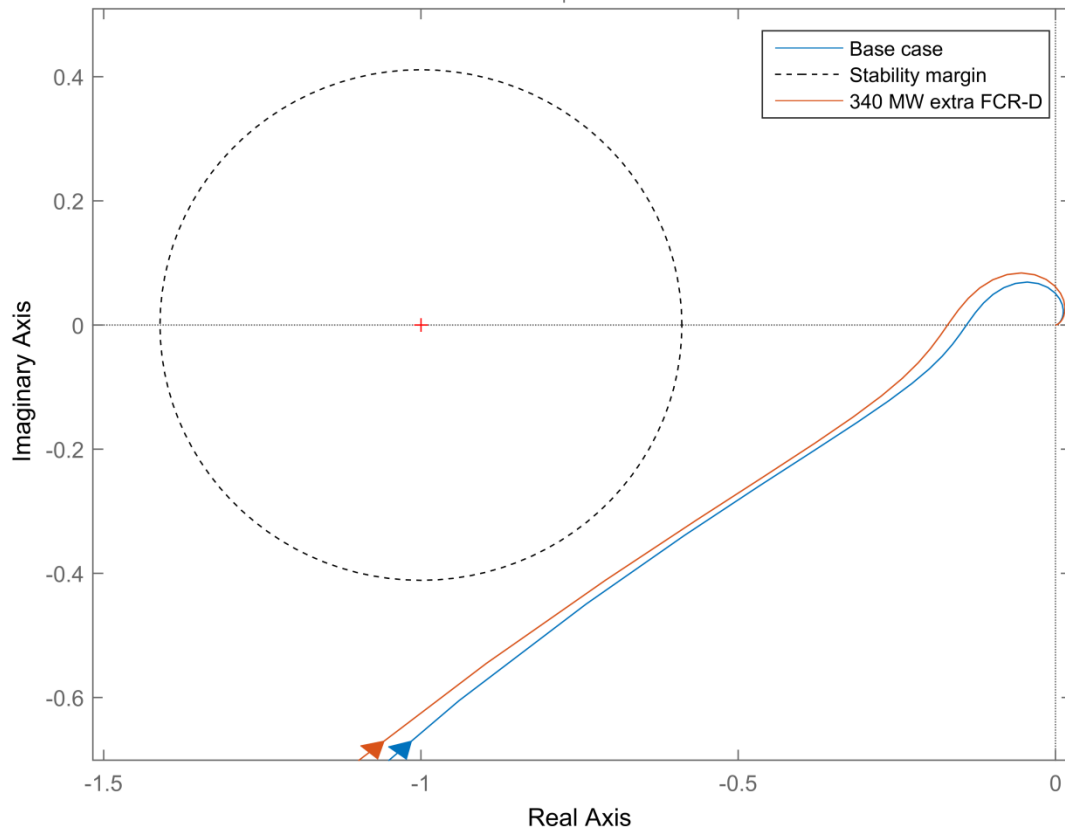


FIGURE 3-18 NYQUIST PLOT WITH AN EXAMPLE OF ADDITIONAL FCR-D IN AN ESTIMATED MODEL

Figure 3-18 shows the Nyquist plot of the estimated model. Note that the margins have not been validated due to the complexity. The figure also exemplifies the influence of additional regulating strength. As can be seen there is quite some distance at the points where the Nyquist curves cross the real axis and the stability circle and that it allows additional regulating strength without violating the stability margins.

3.3.3 SIMULATION MODEL: VALIDATION

The best model parameter set, as shown in Table 3-7, is validated by using three other disturbances. These disturbances are chosen during the same time period as the tuning disturbances, August 2015 up to and including August 2016. That's the reason why two of the power imbalances of the validation disturbances are smaller compared to the tuning disturbances. "Unfortunately" there are not any more disturbances available with a major power imbalance during the selected time period. The system data for the validation disturbances are shown in Table 3-8.

TABLE 3-8 VALIDATION DISTURBANCES AND PARAMETERS

| Disturbance | Date & Time | Power imbalance [MW] | Estimated kinetic energy [GWs] | System load [GW] |
|--------------------|------------------------|-----------------------------|---------------------------------------|-------------------------|
| 1 | 2015-09-16 13:35:56 | -500 | 235 | 40.0 |
| 2 | 2016-02-20 09:45:35 | -875 | 255 | 51.1 |
| 3 | 2016-08-28 22:06:11 | -590 | 223 | 34.0 |

The validation results are shown in Figure 3-19, Figure 3-20, and Figure 3-21. The most important information of the simulations is the minimum instantaneous frequency during the disturbance. A comparison between the minimum instantaneous frequency of the measured and simulated frequency traces is shown in Table 3-9.

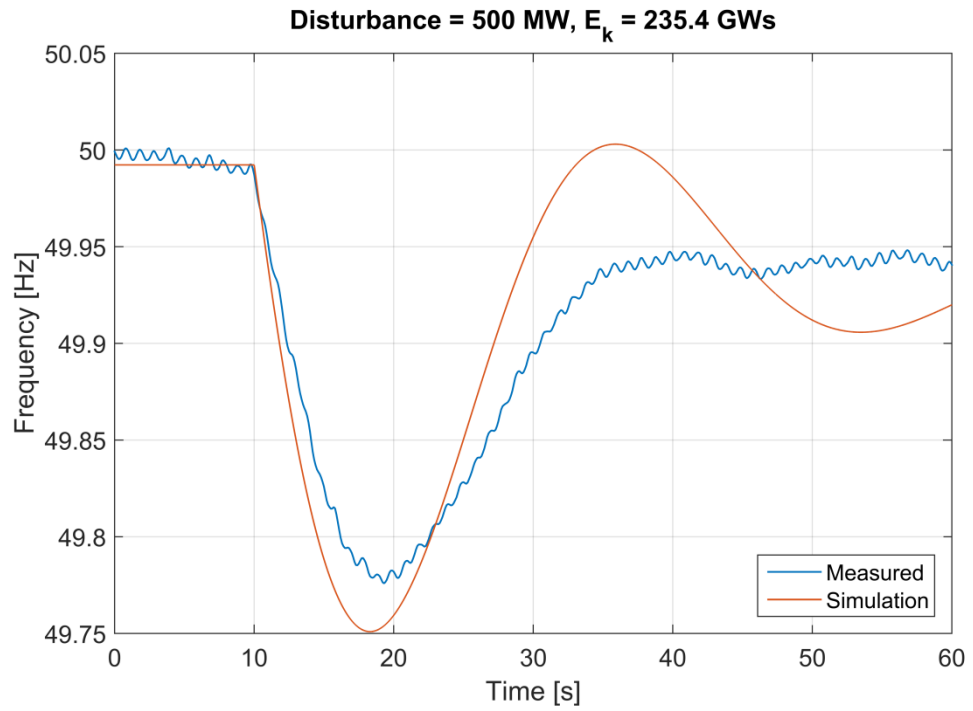


FIGURE 3-19 VALIDATION DISTURBANCE 1

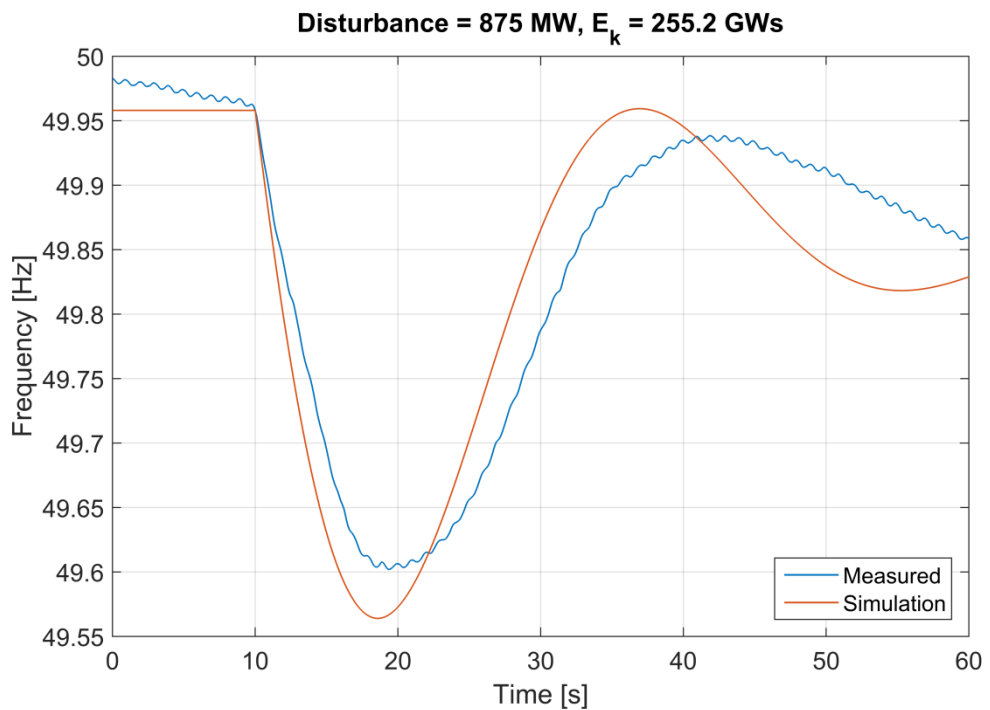


FIGURE 3-20 VALIDATION DISTURBANCE 2

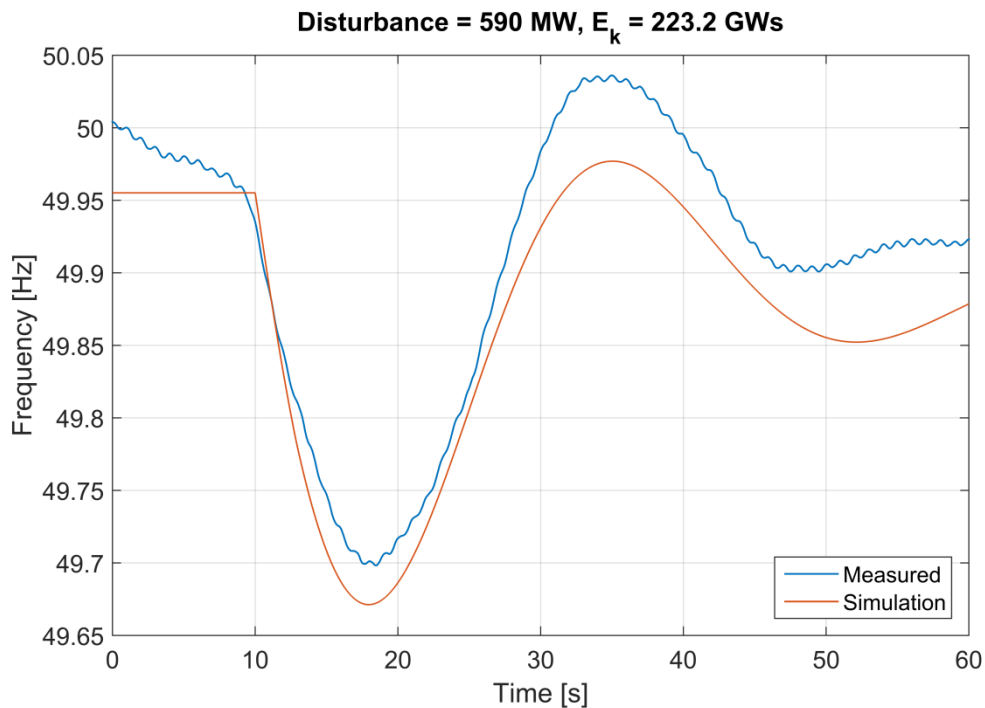


FIGURE 3-21: VALIDATION DISTURBANCE 3

TABLE 3-9 COMPARISON OF MINIMUM INSTANTANEOUS FREQUENCY BETWEEN THE MEASURED AND SIMULATED FREQUENCY TRACES

| Disturbance | Frequency deviation [Hz] |
|-------------|--------------------------|
| 1 | 0.03 |
| 2 | 0.04 |
| 3 | 0.03 |

The validation results show that the model has a similar accuracy for all three disturbances. The simulated frequency is in all cases just below the measured one. The results show that the simulation model can be used to estimate the frequency behaviour in a good way, based on the current frequency control.

4. EXPERIENCES IN OTHER SYNCHRONOUS AREAS

The structural changes that have been identified in the Nordic power system are not a unique “Nordic synchronous area”-challenge. Similar changes should have occurred in other small and medium-sized synchronous areas. To benefit of the experience gained in other small and medium-sized synchronous systems, a survey was sent out during the summer of 2016 with a result of 11 answers. A summary of the responses received is captured in the sections below. Overall, the data in this overview refers to 2015 if nothing else is mentioned. The survey itself can be found in Appendix A.

4.1 SURVEY AND RESPONSES

4.1.1 THE SURVEY

The survey had questions about the system and its properties, such as the description of the synchronous system, countries involved, and the organisation of the dispatch (market driven⁷ or centralised dispatch⁸). It also asked some basic figures that are of interest when dealing with inertia: load (minimum, maximum, average), kinetic energy (minimum, maximum), dimensioning incident in megawatts in the synchronous area, HVDC connections, the share of generation not contributing to kinetic energy (converter-connected generation), and the primary reserves available.

The survey also had a section about inertia assessment; if today's inertia is assessed, and how it is assessed, if future inertia is assessed, and if there is an expected change in the inertia in the future compared with today, and which are the key factors behind such change.

Another section of the survey was about the mitigation of low-inertia situations. The questions focus on how to mitigate low-inertia situations, whether the solutions are market-driven or not, and if the grid code has requirements for the inertia, or for the synthetic inertia, fast-acting reserves, or something else. Also a question about the techniques for applying synthetic inertia was asked for.

A last section concentrated on the frequency, such as the normal frequency range. The under-frequency value or RoCoF value when the load shedding starts, and the over-frequency value (or RoCof) when generation shedding starts were asked for. Also measurements of a frequency curve after a disturbance were requested, as well as a graph of the kinetic energy over a year.

4.1.2 MAIN PROPERTIES OF THE SYSTEMS IN THE SURVEY

Table 4-1 shows an overview of the systems for which answers were received (and the corresponding values for the Nordic synchronous system).

There were 11 organisations which answered, but for some analyses New Zealand is counted as two separate answers since the North Island and the South Island are separate synchronous

⁷ Market driven dispatch means a dispatch controlled and guided by commercial considerations

⁸ Centralised dispatch means a more centralised control and guidance.

systems connected by an HVDC link. Even though Tasmania belongs to Australia's national electricity market (NEM) it is a separate synchronous system. Therefore the answers of Tasmania are separate from Australia's answers.

**TABLE 4-1 BASIC INFORMATION OF THE SYNCHRONOUS SYSTEMS, WHICH ARE IN THE SURVEY
(THE INFORMATION IN THE MATRIX IS BASED ON 2015 DATA)**

| Synchronous area or company name | Country | Min. / Max. load in GW | Min. / Max. kinetic energy /GWs | Specific |
|---|--|-------------------------------|--|---|
| The Nordic power system | Norway, Eastern Denmark, Sweden, Finland | 25 / 70 | 125 / 240 | One synchronous area with four transmission system operators (TSOs) |
| ERCOT | USA | 24 / 70 | 152 / 389 | The Electric Reliability Council of Texas (ERCOT) is the electricity grid and market operator for the majority of the state of Texas. |
| National Grid (NG) | Scotland, Wales, England | 17 / 53 | 130 ⁹ / NA | NG is the National Electricity Transmission System Operator (NETSO), for Great Britain |
| Eirgrid | Ireland | 2.3 / 6.4 | 20 / 46 | The synchronous power system of the island of Ireland comprises of both the EirGrid-controlled Irish system and the SONI-controlled Northern Irish system. |
| Transpower | New Zealand (North Island) | 1.7 / 4.5 | 20 / 41 | Two synchronous areas: North Island and South Island. The islands are connected with an HVDC link. |
| Transpower | New Zealand (South Island) | 1.3 / 2.2 | 11 / 25 | |
| Faroe island | Denmark | 0.02 / 0.05 | Not available | |
| Australia | Queensland, Victoria, New South Wales, and South Australia | 14 / 30 | 72 / 50 | Australia and Tasmania are two different synchronous areas of NEM connected by HVDC, equipped with a fast-acting frequency controller attempting to hold both frequencies together. |
| Tasmania | Tasmania | 0.9 / 1.7 | 4 / 10 | |
| ESKOM | South Africa | 19 / 35 | Not measured | |
| Rhodes | An island in Greece | 0.032 / 0.191 | 0.15 / 0.63 | |
| Hydro-Quebec TransEnergie | Canada | 15 / 39 | 60 / 160 | Synchronous area is the Quebec interconnection. Almost all of the interconnection is located on the territory of Québec. |

⁹ National Grid, System Operability Framework 2016, www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937803

Most systems have a market-driven dispatch, three systems (ESKOM, Faroe Islands, and Hydro-Quebec TransEnergie) have a centralised dispatch, whereas Rhodes in Greece is in a transition towards a market-driven dispatch.

Figure 4-1 presents the kinetic energy values for the systems under analysis, and Figure 4-2 shows the system load values. As the system sizes vary significantly, two graphs exist for load values.

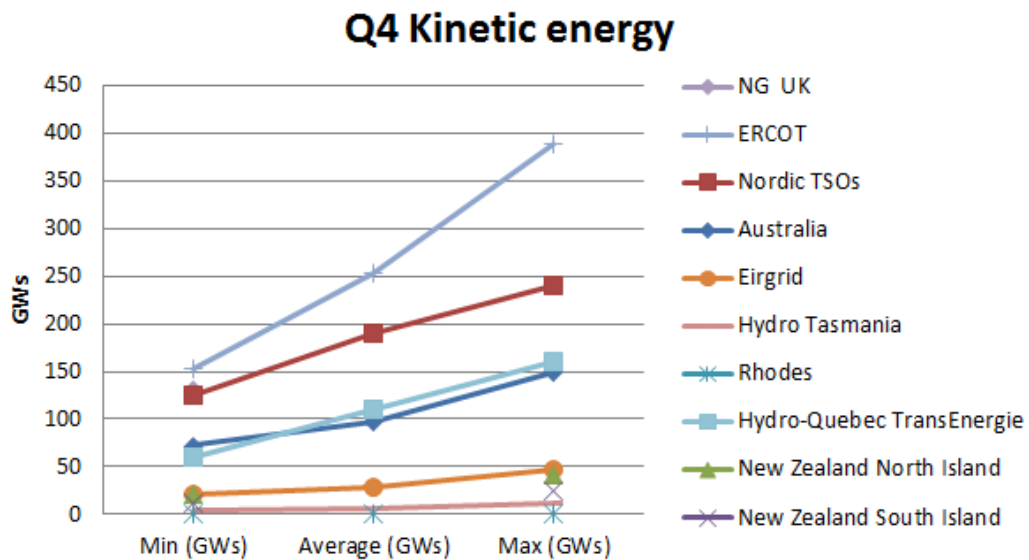


FIGURE 4-1 THE MINIMUM, AVERAGE AND MAXIMUM KINETIC ENERGY VALUES FOR THE SYSTEMS NATIONAL GRID INFORMED THE MINIMUM VALUE ONLY

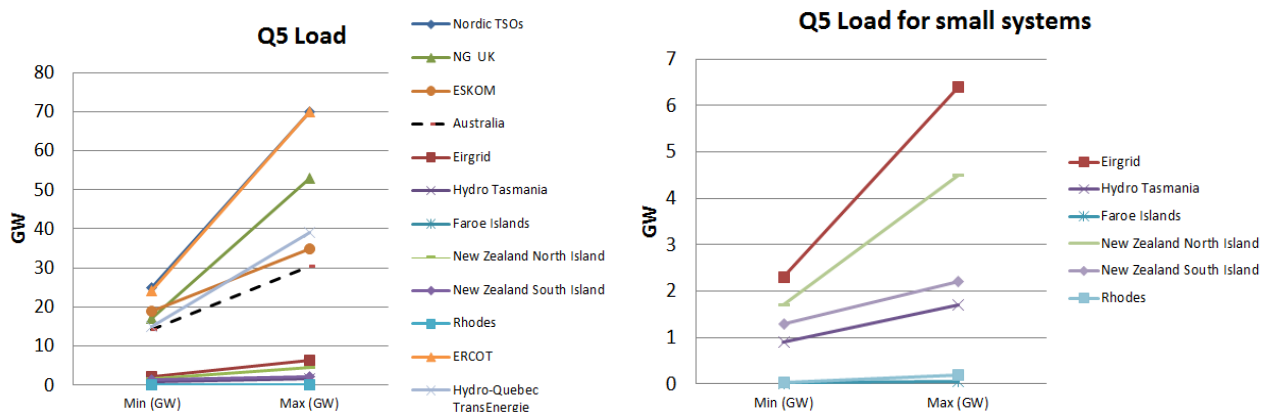


FIGURE 4-2 THE MINIMUM AND MAXIMUM LOAD VALUES FOR THE SYSTEMS. FIGURE (LEFT) SHOWS ALL THE SYSTEMS UNDER ANALYSIS WHILE FIGURE (RIGHT) SHOWS SYSTEMS WITH LOADS LESS THAN 10 GW

Figure 4-3 shows the dimensioning incident for the systems under survey. Dimensioning incidents are the highest expected instantaneously-occurring active power imbalances in both positive and negative direction.

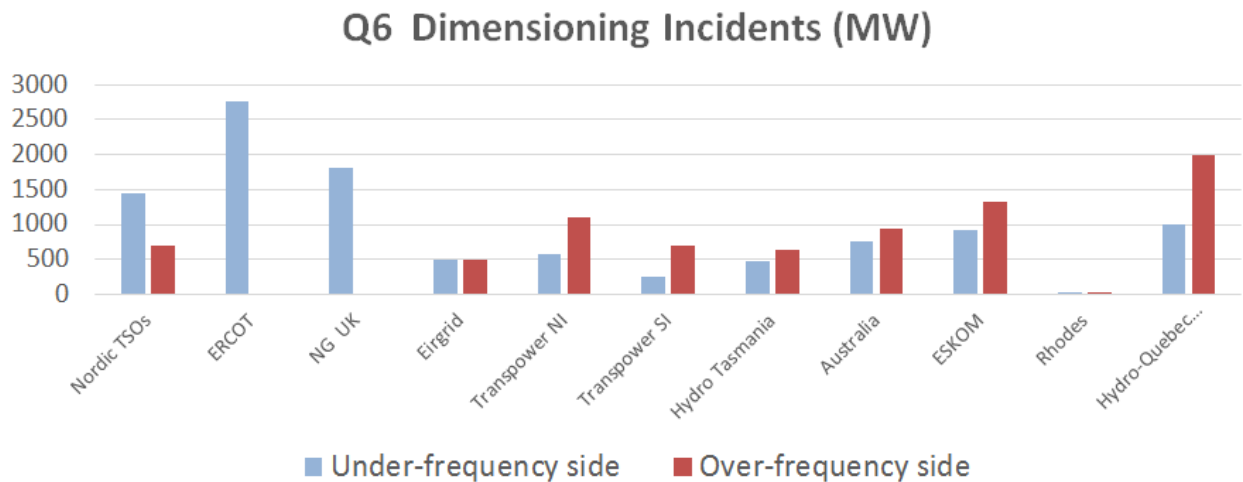


FIGURE 4-3 THE LARGEST LOSS (DIMENSIONING INCIDENT), THAT CAN HAPPEN IN THE SYSTEM. NI = NORTH ISLAND, SI = SOUTH ISLAND FOR RHODES THE VALUES ARE 26 MW FOR UNDER-FREQUENCY AND 33 MW FOR OVER-FREQUENCY

Tasmania reports the penetration of non-synchronous generation based on the SNSP index¹⁰. Tasmania experiences periods of SNSP around 70 % up to six hours and maximum SNSP values up to 80 %. However, during these periods the system inertia is increased by contribution of synchronous condensers which is not reflected in the SNSP.

Figure 4-4 presents the total installed generation capacities in the systems, and the installed capacity of the generation not-contributing to inertia plus HVDC capacity. Figure 4-5 shows the percentage values of generation that does not contribute to inertia and import HVDC capacities as a share of the installed generation.

¹⁰ The SNSP index is the System Non-Synchronous Penetration (SNSP) ratio and is calculated in the following way: $SNSP = (P1 + P2)/(P3 + P4)$, where $P1$ is wind power generation, $P2$ is HVDC import, $P3$ is load, and $P4$ is HVDC export, all in megawatts.

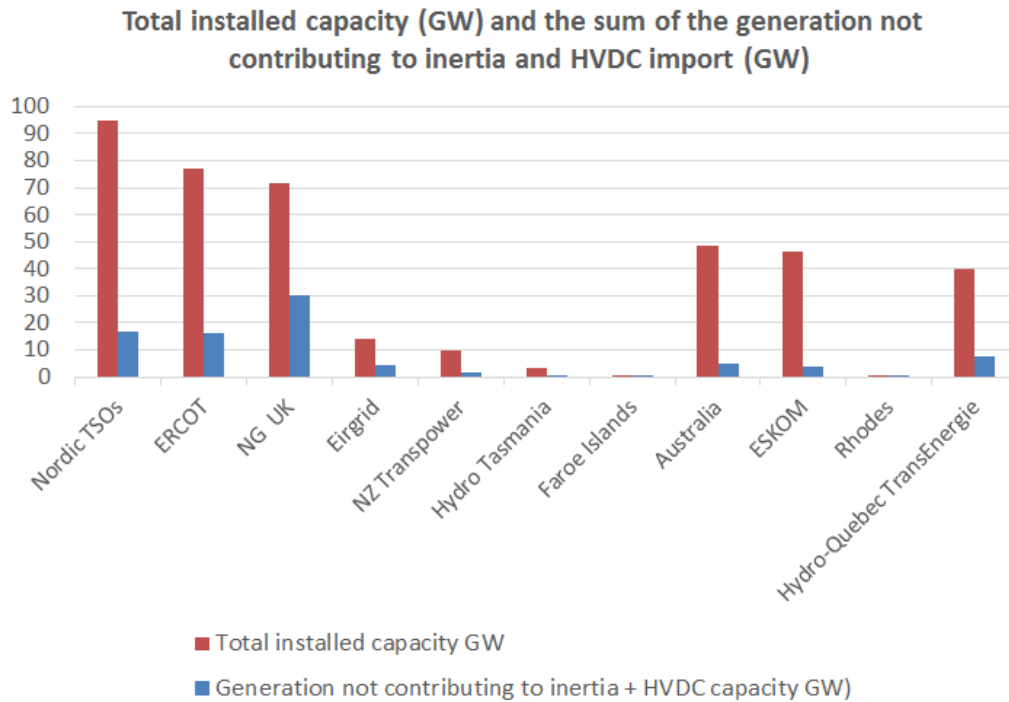


FIGURE 4-4 THE TOTAL INSTALLED CAPACITY AND THE AMOUNT OF NON-SYNCHRONOUS GENERATION, BOTH IN GIGAWATTS. FOR ERCOT THE NUMBER REPRESENTS SUMMER PEAK DEMAND WHERE INSTALLED WIND AND SOLAR GENERATION CAPACITY ARE DISCOUNTED BASED ON CAPACITY CONTRIBUTION AND SUMMER RATINGS FOR THERMAL GENERATION ARE USED

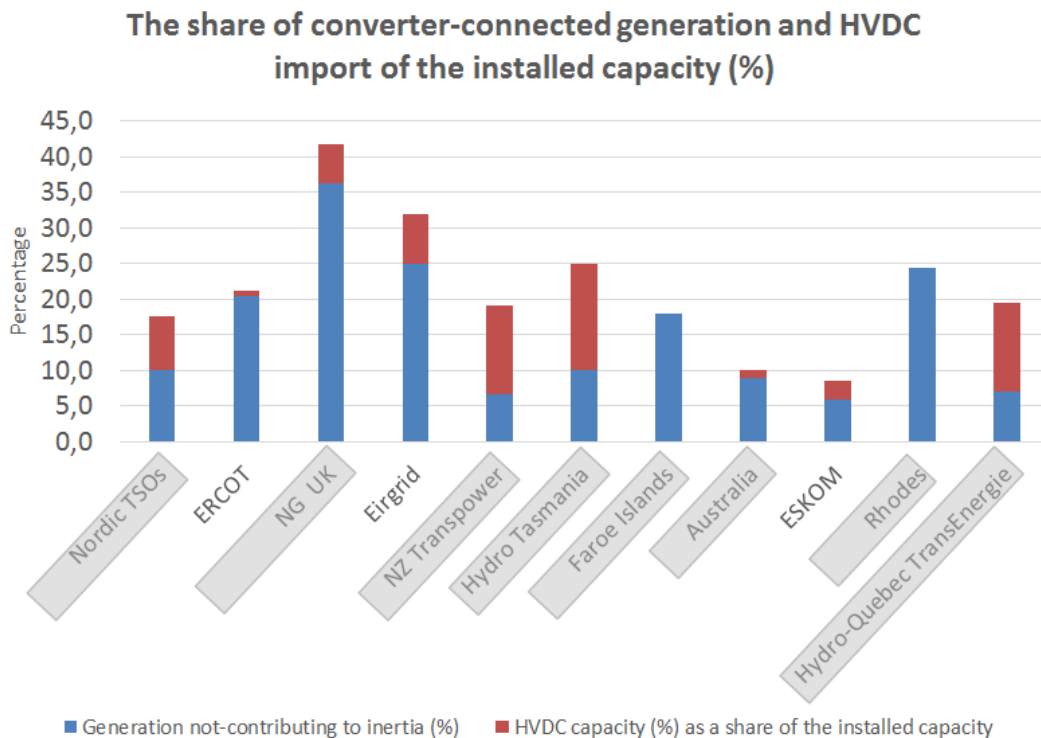


FIGURE 4-5 THE SHARE OF THE (COMBINED) INSTALLED CAPACITY OF GENERATION NOT CONTRIBUTING TO INERTIA AND THE TRANSMISSION CAPACITY OF HVDC IMPORT IN PERCENTAGES OF THE SYSTEM INSTALLED CAPACITY. (IN TASMANIA, THE SHARE OF CONVERTER CONNECTED GENERATION CAN GET AS HIGH AS 30 % IN THE NIGHT.)

Figure 4-5 shows that the share of generation that does not contribute to the inertia and HVDC import exceeds 30 % in two systems: the UK and Ireland. For three systems, the share is about 20 –25 %. This does not directly express the number of hours when the inertia is low, but it is an indicator that there may be hours when the inertia is low. The TSOs that consider inertia to be an issue are marked with a grey box in Figure 4-5.

Figure 4-5 also shows that Eirgrid and ERCOT have a quite high share of generation that is not contributing to the inertia and HVDC import, but do not consider inertia to be an issue today. ERCOT states that they have enough inertia at the moment, and that they are monitoring the situation. In 2014, ERCOT performed dynamic simulations for dimensioning their reserves. Eirgrid does not consider low inertia to be an issue for the system today, but the future trends indicate that inertia will decline as the penetration of non-synchronous renewable generation increases further. The TSOs in Ireland have engaged in a number of activities to mitigate the impacts of lower inertia on the system through their DS3 programme¹¹.

The numbers for ERCOT in Figure 4-5 represent the total installed generation capacity. ERCOT has also measured the contribution of wind power generation as a share of the total load, which are presented in Table 4-2. The highest share was in 2016, when the wind power generated 48 % of the total load.

TABLE 4-2 THE DAYS IN RECENT YEARS WITH THE HIGHEST WIND POWER PENETRATION RATE IN ERCOT

| | 2013 | 2014 | 2015 | 2016 |
|--|--------------------|---------------------|-------------------|---------------------|
| Penetration record date | March 9 at 3:15 am | Nov 3 at 2:28:56 am | Dec 20 at 3:05 am | March 23 at 1:10 am |
| Installed Wind Capacity at the time (P_{wind_inst}), MW | 10 570 | 12 527 | 16 170 | 16 547 |
| P_{wind} / P_{load} | 35.8 % | 39.93 % | 44.71 % | 48.28 % |
| P_{wind} , MW | 8 773 | 9 882 | 13 058 | 13 154 |
| P_{wind} / P_{wind_inst} | 83 % | 78 % | 81 % | 79 % |
| Net Load ($P_{load} - P_{wind}$), MW | 15 716 | 14 868 | 16 150 | 14 091 |
| Kinetic energy, MWs | 134 196 | 154 599 | 158 970 | 148 798 |

The dimensioning incident divided by the kinetic energy (Figure 4-6), shows that for small systems, the largest loss compared to the system kinetic energy, can be remarkably higher than for medium-sized systems. Especially when comparing the largest loss and minimum kinetic energy, the ratios are significantly higher for smaller system, such as Rhodes.

¹¹ In response to binding National and European targets, EirGrid Group began a multi-year programme, “Delivering a Secure, Sustainable Electricity System” (DS3). More info at: <http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/>

Largest loss (MW) / Wkin (GWs)

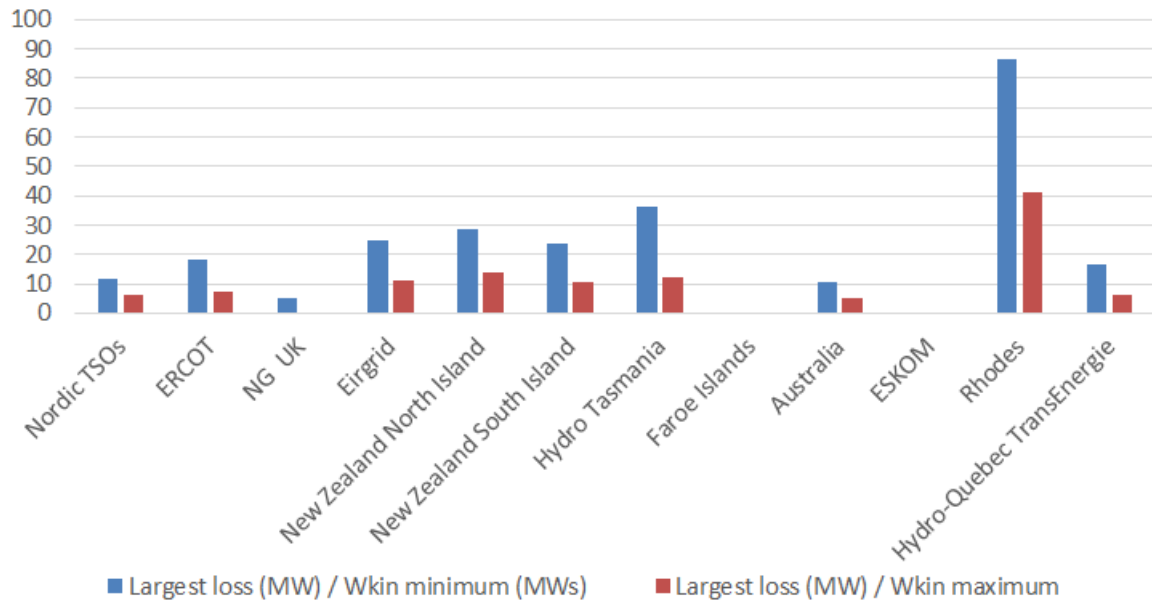


FIGURE 4-6 THE LARGEST LOSS (DIMENSIONING INCIDENT) IN MEGAWATTS DIVIDED BY THE SYSTEM MAXIMUM AND MINIMUM KINETIC ENERGY IN GIGAWATTSECONDS

Figure 4-7 shows the ratio of disturbance reserves and dimensioning incidents.

Primary reserves for disturbances / dimensioning incident

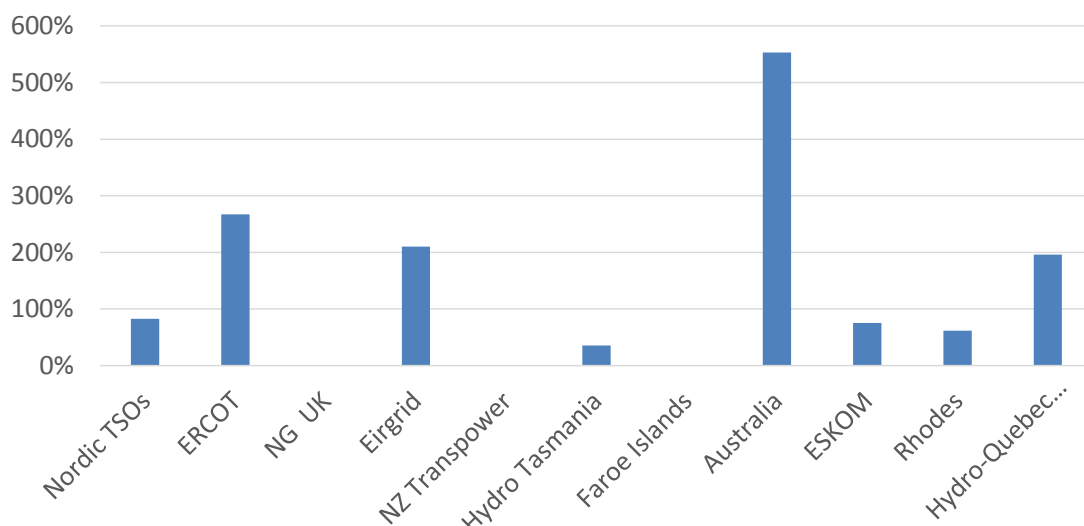


FIGURE 4-7 PERCENTAGE OF DIMENSIONING INCIDENT BEING MITIGATED BY PRIMARY RESERVES IF THE AMOUNT OF RESERVES VARIES ACCORDING TO THE SITUATION, THE MAXIMUM AMOUNT IS USED, WHEN THIS VALUE IS PROVIDED¹²

¹² ERCOT's requirement as shown on the figure is for the case if all primary reserves are provided by generators through governor response. However currently up to 50 % of ERCOT's primary reserve requirement can be provided by load resources. Depending on

The explanation for the high value for Australia in Figure 4-7 is that Australia (excluding Tasmania) covers a huge area (Victoria, New South Wales, Queensland, and South Australia), with reserves present in the different regions.

Figure 4-1 to Figure 4-7 show that there are variations in the systems when it comes to the system load, kinetic energy, dimensioning incident, and reserves. The reasons for the differences are diverse. The acceptable frequency deviation tends to be larger in smaller systems, which explains to some extent why smaller systems can accept relatively larger dimensioning incidents. The normal frequency range in Rhodes is $50 \text{ Hz} \pm 1 \text{ Hz}$, while the corresponding frequency range for other systems is smaller and the deviation from the nominal frequency varies between 0.017 Hz (ERCOT) and 0.5 Hz (Faroe Island). The share of non-synchronous generation varies both between the systems, and in the same system depending on the generation and exchange situation and this explains the variations to some extent.

Most synchronous systems (eight) have a market-driven dispatch, three systems (ESKOM, Faroe Islands, and Hydro-Quebec TransEnergie) have a centralised dispatch, and one system (Rhodes) is in a transition towards a market-driven dispatch.

For eight synchronous systems (NZ has been counted twice, being two synchronous areas), low inertia is an issue at the moment, whereas three answered that currently inertia is not an issue (for the intact grid). When describing the inertia, six systems mentioned frequency stability or maintaining frequency as a challenge, especially frequency after trips of importing HVDC links or after the trip of generators. Two systems mentioned voltage oscillations after a generator trip in this respect. The systems face inertia problems with high HVDC import, when generation from converter-connected power plants is high, with low amounts of generation from conventional synchronous generators, when the demand is low, or when hydro reservoirs have low storage levels.

4.2 MAIN OBSERVATIONS

4.2.1 LOW INERTIA AS A CHALLENGE

More than half of the synchronous systems under survey (eight out of 12) indicated that the decreasing inertia is a challenge. According to the answers, the key factor for the transition towards less inertia in the system, is the change in the generation mix. This change reduces the share of the thermal power, or replaces (large) thermal units with smaller units, and increases the share of non-synchronous generation (such as wind, PV). The following reasons behind this change were mentioned: fossil-fuel costs, CO_2 emission prices, EU-directive towards renewables, aims to have a fossil-free future in 2030. Other reasons mentioned, were increased imports via HVDC lines or via weak AC lines, and customer-installed distributed photovoltaic generation systems.

In Tasmania, inertial problems became apparent about 10 years ago, mainly due to growing wind farm generation and the presence of HVDC, capable of importing up to more than 50 % of the

system inertia conditions, load resources are found to be up to 2.3 times more efficient than generators when providing frequency response, due to their deployment logic. Therefore, overall lower (than what is shown on Figure 4-7) amount of total primary reserve can be procured, due to load resources participation in this Ancillary Service.

minimum demand. The problem has been managed by dispatch constraints linking maximum Tasmanian HVDC import with the minimum system inertia, operating hydro units on low output, and operating hydro units in synchronous condenser mode. In recent years, the problem became much more spread, affecting other parts of Australia's NEM and specifically South Australia. The recent system security review has recommended a number of Electricity Rule changes to address the issue of minimum synchronous generation including defining minimum system inertia, minimum fault level for specific locations, introduction of RoCoF limits, and the introduction of a protected event which is a multiple contingency identified due to its high impact on the system.

4.2.2 PLANNING THE RESERVES FOR OPERATION

Three systems describe the procedure how they dimension the amount of reserves the system needs for a secure operation. ERCOT, National Grid (NG) in the United Kingdom, and New Zealand Transpower dimension the needed disturbance reserves according to the system state. ERCOT determines the minimum requirement of RRS (Responsive Reserve Service) based on expected system inertia conditions. The reserves in NG vary and are based on system demand and the largest loss being covered. In New Zealand the primary reserves are purchased depending on the size of the risk on the system. They have a market tool, the Reserve Management Tool (RMT), which carries out a dynamic study for each trading period to calculate the amount of reserves required.

4.2.3 INERTIA ASSESSMENT

Among the 11 answers, nine stated that they assess the current system inertia, and seven have an on-line inertia assessment in place. Eight systems assess the future inertia. Two systems assess the inertia today with dynamic simulations (NZ Transpower, ESKOM), six use generation connection data from the SCADA, and combine this with turbine-generator kinetic energy (Nordic, Eirgrid, ERCOT, Faroe Island, NG UK, and Hydro-Quebec TransEnergie).

Five systems use inertia assessment for knowledge building (Nordic TSOs, ERCOT, NZ Transpower, and Faroe Island) and/or archive them for studies (Hydro-Quebec TransEnergie). ERCOT considers the inertia to be adequate at the moment but they are monitoring the trend of the decreasing inertia in the system. NG uses the inertia estimation to check the maximum loss (in megawatts) that the system can face without exceeding the RoCof Limit. Eirgrid uses the inertia estimation as a part of the operational constraints; they have a requirement that the system inertia should not fall below 20 000 MWs.

4.2.4 MITIGATION MEASURES FOR LOW-INERTIA SITUATIONS

In today's power system, the systems deal with low-inertia situations in different ways. Three systems (Nordic TSOs, Australia, and ESKOM) indicate that they have no solution in place for dealing with low-inertia situations at the moment. Two systems (ERCOT, Transpower in NZ) have market-based solutions, while six systems (Eirgrid, Faroe Island, NG, Rhodes, Tasmania, and Hydro-Quebec TransEnergie) have non-market-based solutions. Several answerers do not mention explicitly the details of their non-market based solutions. Eirgrid indicates that their non-market based solutions include a central procurement with regulated tariffs, which is expected to transition into an auction-based approach in the future.

The existing solutions can be classified in different groups based on the techniques used (Q13, Q14):

1. Increasing reserves (generation and load) (NZ Transpower, UK, ERCOT, Tasmania).
2. Having some kind of operational limits for the system such as a minimum kinetic energy (20 GWs, Eirgrid), limiting the flow on weak AC interconnections (some parts in Australia), ensuring that the RoCoF does not increase after a generator loss (NG UK), or imposing power limitations to avoid UFLS caused by a single contingency (Hydro-Quebec TransEnergie), and dispatch constraints linking the maximum HVDC import with the minimum system inertia (Tasmania).
3. Running at almost idle or minimum power with hydro or thermal units (Faroe Islands, Tasmania).
4. Contracted load disconnections as primary reserve using load under-frequency relays. ERCOT, Australia, and Rhodes mention this, but all systems have under-frequency load shedding (according to Q19).
5. Running hydro units in synchronous condenser mode (Tasmania)
6. Using frequency control SPS (FCSPS) that reduces the size of the largest contingency by tripping the required amount of load/generation (Tasmania)

Some systems have plans for the near future (2020–2025) or the far future (2025–), for dealing with low inertia. More reserves, synthetic inertia (as an ancillary service for example), more flexible thermal units, adding connections to other synchronous systems, and services from battery storage are mentioned in this respect.

Only Hydro-Quebec TransEnergie has a grid code requirement for inertia. It boils down to the following requirements: *“For conventional synchronous generators, synchronized to the grid, the inertia constant must be compatible with the inertia constants of existing power plants in the same region. The interconnection study will specify any minimum inertia constant that applies to generating units. Wind power plants greater than 10 MW must be equipped with a frequency control system. The system must reduce large, short-duration frequency deviations, at least as much as does the inertial response of a conventional synchronous generator whose inertia equals 3.5 s.”*

Among the tools for mitigating low-inertia situations, a question is explicitly asked about synthetic inertia or similar methods. There are two systems applying synthetic inertia: Faroe Islands and Hydro-Quebec TransEnergie. Hydro-Quebec TransEnergie gets the synthetic inertia from wind generation. Faroe Islands gets its synthetic inertia from a 2.3 MW battery, which has the first priority to smoothen the power from Húsahagi windfarm. The battery system is also able to make an instant discharge and give frequency support as virtual inertia. Eighteen wind turbines in Faroe Island have virtual inertia power support but these configurations are undergoing changes at the moment. These are all units connected via power-electronic converters.

The others have various tools such as HVDC, power-electronic converters, or load reduction (RRS), but do not state them being synthetic inertia. The answers presented in Figure 4-8 show an indication of the types of mitigation measures, and the resources providing it. The figure has therefore no dimensions.

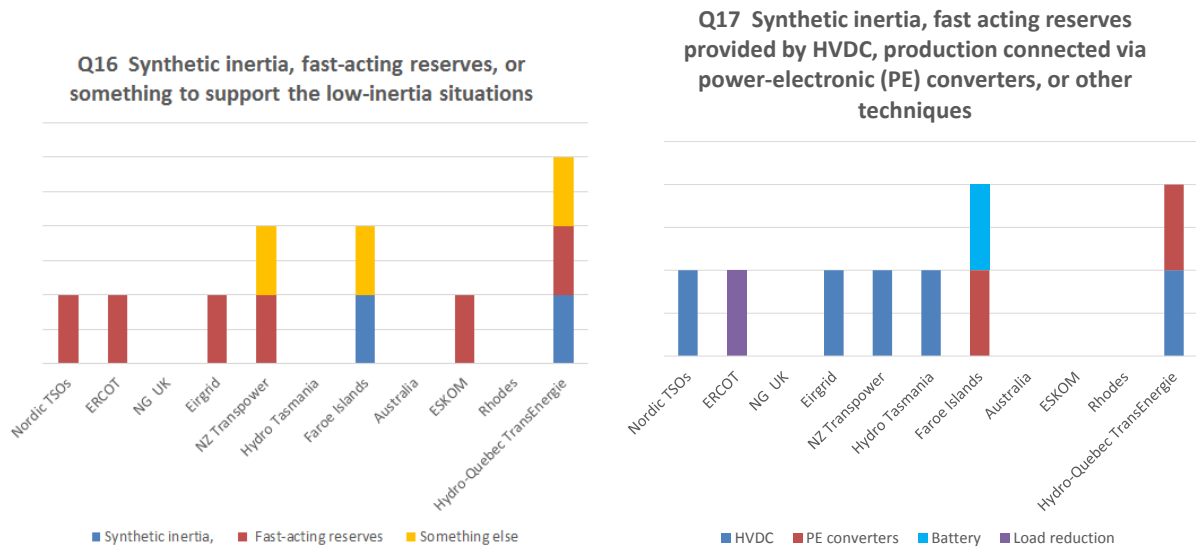


FIGURE 4-8 SYNTHETIC INERTIA, FAST-ACTING RESERVES, AND OTHER TOOLS FOR SUPPORTING THE SYSTEM IN LOW-INERTIA SITUATIONS

4.2.5 FREQUENCY AND FREQUENCY CHANGES

The normal frequency variations tend to be larger in smaller systems and vice versa. The normal frequency range in Rhodes is 50 Hz ± 1 Hz, while the corresponding frequency range for other systems is smaller and the deviation from the nominal frequency varies between 0.017 Hz (ERCOT) and 0.5 Hz (Faroe Island).

For load shedding, all the 12 synchronous systems have under-frequency limits when the load shedding starts (Figure 4-9). In addition, Hydro Quebec TransEnergie has RoCoF limits for starting load shedding. Eight systems have over-frequency limits for starting generation curtailment (Figure 4-10). Most systems have automatic generation curtailment, but some start generator curtailment manually.

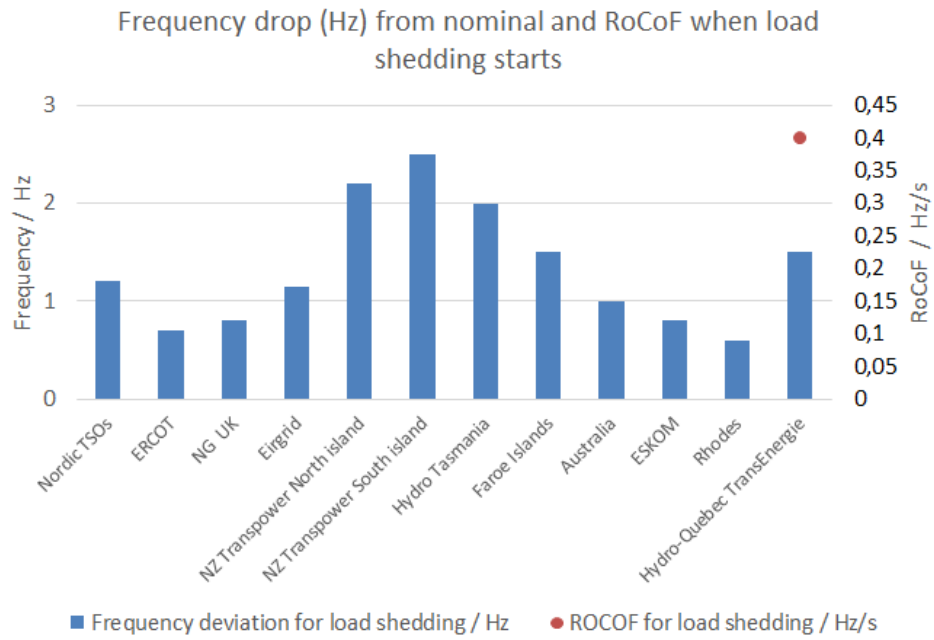


FIGURE 4-9 THE ABSOLUTE FREQUENCY DROP AND ROCoF WHEN LOAD SHEDDING STARTS

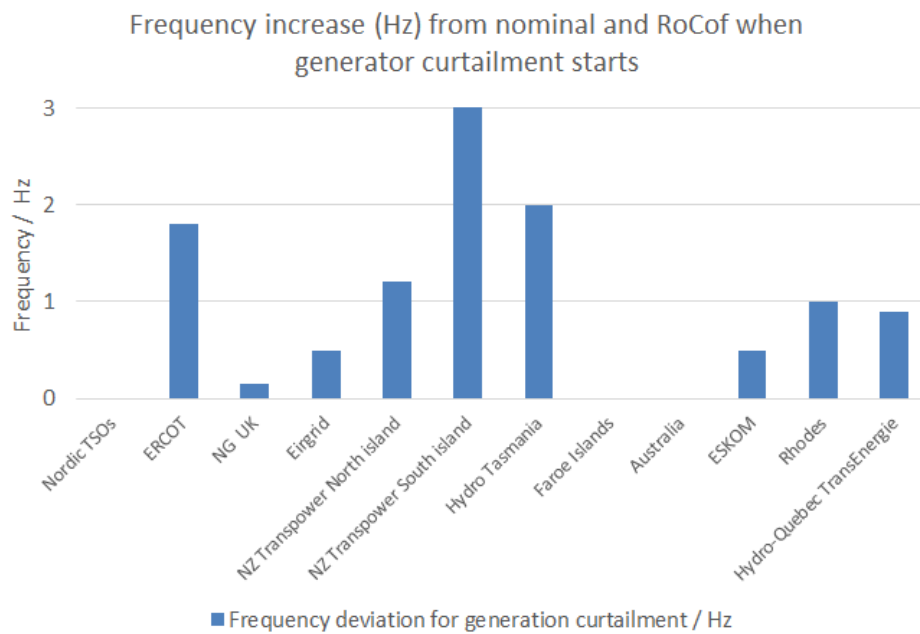


FIGURE 4-10 THE FREQUENCY INCREASE WHEN GENERATOR CURTAILMENT STARTS

5. FUTURE KINETIC ENERGY ESTIMATION

As mentioned in the introduction of this report, the Nordic power system is changing. The main drivers of the changes are climate policy, which in turn stimulates the development of more Renewable Energy Sources (RES), technological developments, and a common European framework for markets, operation and planning. While the system transformation has already started, the changes will be much more visible by 2025. The structural changes will challenge the operation and planning of the Nordic power system. The main changes relate to the following [1]:

- The closure of thermal power plants. Almost all condensing power plants have already been closed and there is also a significant risk that the amount of Combined Heat and Power (CHP) will be reduced due to profitability reasons.
- The share of wind power in the Nordic power system is rising. Installed capacity for wind power has expected to triple in the period 2010–2025. In the end of 2016 the installed capacity in the Nordic synchronous area has been app. 10.1 GW and it is expected to be app. 17.3 GW in the end of 2025.
- Swedish nuclear power plants will be / are decommissioned earlier than initially planned (four reactors with a total capacity of 2 900 MW – Ringhals 1, Ringhals 2, Oskarshamn 1, and Oskarshamn 2 – will be decommissioned by 2020) while Finland will construct new nuclear capacity (Olkiluoto 3, 1 600 MW, which will be in operation in late 2018).
- The capacity from interconnectors between the Nordic synchronous area and other synchronous areas will increase with almost 50 % in 2025, due to several new HVDC connections, such as: Kriegers Flak 400 MW (back-to-back, Eastern Denmark – Germany), Nord Link 1 400 MW (Norway–Germany), North Sea Link 1 400 MW (Norway–England), Hansa PowerBridge 700 MW (Sweden–Germany).

In order to assess the impact of the changes ongoing and foreseen on the kinetic energy in the system, future market scenarios have been defined by the Nordic TSOs for the years 2020 and 2025. These market scenarios are input for market simulations, where the power production and corresponding market prices are simulated, based on data corresponding to different inflow years. In this way, we obtain a forecast of the (blocks of) units that will be producing power in the years 2020 and 2025. Those (blocks of) units bring inertia into the system, and by mapping those blocks to individual generation units, of which the inertia constant are known, an estimate of the kinetic energy in the system can be computed. The overview of the kinetic energy estimation in the future scenarios is schematically depicted in Figure 5-1.

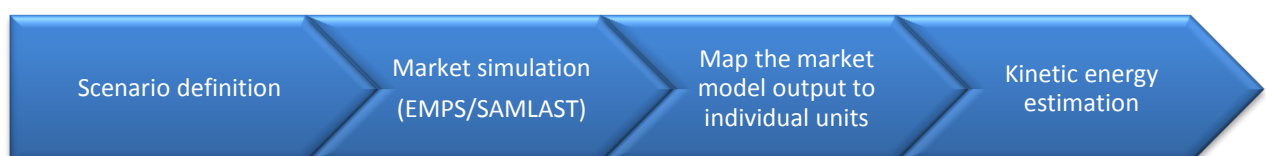


FIGURE 5-1 FUTURE KINETIC ENERGY ESTIMATION

The different steps in the chain of simulations, are highlighted in the following sections.

5.1 SCENARIO DEFINITION

In this section, the first step in the simulation chain in Figure 5-1 is elaborated upon: the scenario definition. The scenario is constructed as a best-estimate scenario, i.e. it describes the market development that is regarded most probable. It is, however, still called a scenario and not a forecast as the uncertainties grow over time. From this scenario, the years 2020 and 2025 are used for the simulations and further analysis.

As a reference the current¹³ market situation is presented below. The total installed capacity in the Nordic countries is 105 GW and the production 396 TWh, with a surplus of 16 TWh.

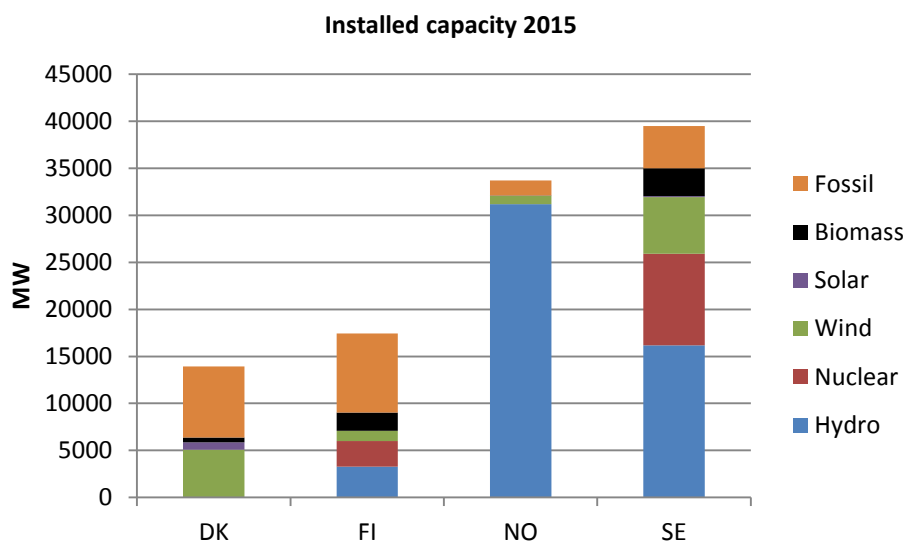


FIGURE 5-2 INSTALLED CAPACITY FOR DIFFERENT CATEGORIES IN THE NORDIC COUNTRIES. SOURCE: ENTSO-E

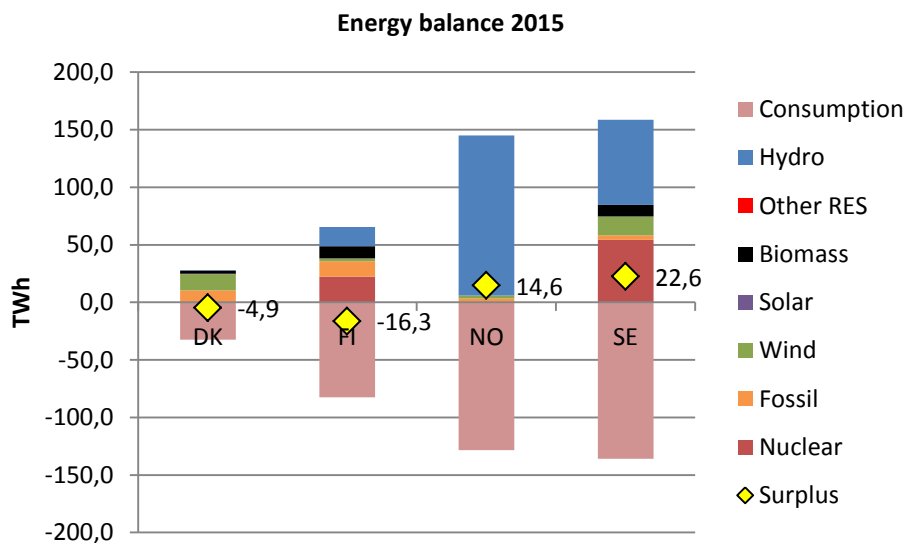


FIGURE 5-3 ENERGY BALANCES FOR THE NORDIC COUNTRIES. SOURCE: ENTSO-E

¹³ The most recent statistics is for 2015. Data from ENTSO-E.

The capacity on the interconnectors between the Nordic synchronous area and neighbouring synchronous areas is 7.8 GW as can be seen in Table 5-1. The full capacity is, however, not always available due to internal bottlenecks in the German and Polish grids. The availabilities for some of the interconnectors or borders are shown in Table 5-2; the numbers are based on historical values, and show the annual average capacity as a percentage of the nominal capacity. Interconnectors missing in the table are modelled with full (100 %) availability. The seasonal variation of the availability on the interconnectors between Sweden–Germany and Sweden–Poland are shown in Figure 5-4.

TABLE 5-1 CAPACITIES ON INTERCONNECTORS BETWEEN THE NORDIC SYNCHRONOUS AREA AND NEIGHBOURING SYNCHRONOUS AREAS
(IN THE TABLE, THE FIRST VALUE INDICATES THE CAPACITY IN THE FROM–TO DIRECTION, AND THE SECOND VALUE REFERS TO THE OPPOSITE DIRECTION; A SINGLE VALUE INDICATES THAT THE CAPACITY IS THE SAME IN BOTH DIRECTIONS.)

| From | To | Capacity [MW] Year 2015 | Capacity [MW] Year 2020 | Capacity [MW] Year 2025 |
|--------------|-----------------|----------------------------|----------------------------|----------------------------|
| Denmark East | Germany | 600 | 1 000 | 1 000 |
| Denmark East | Denmark West | 600 | 600 | 600 |
| Finland | Estonia | 1 000 | 1 000 | 1 000 |
| Finland | Russia | 350 / 1 400 | 350 / 1 400 | 350 / 1 400 |
| Norway | Germany | 0 | 1 400 | 1 400 |
| Norway | Denmark West | 1 632 | 1 632 | 1 632 |
| Norway | England | 0 | 0 | 1 400 |
| Norway | The Netherlands | 723 | 723 | 723 |
| Sweden | Germany | 615 | 615 | 1 315 |
| Sweden | Denmark West | 680 / 740 | 680 / 740 | 680 / 740 |
| Sweden | Lithuania | 700 | 700 | 700 |
| Sweden | Poland | 600 | 600 | 600 |
| Sum | | 7 850 / 8 610 | 9 650 / 10 410 | 11 750 / 12 510 |

TABLE 5-2 AVAILABILITIES ON SOME OF THE INTERCONNECTORS/BORDERS;
THE NUMBERS ARE BASED ON HISTORICAL VALUES, AND SHOW THE ANNUAL AVERAGE CAPACITY AS A PERCENTAGE OF THE MAXIMUM NET TRANSFER CAPACITY. INTERCONNECTORS NOT LISTED IN THE TABLE ARE MODELLED WITH 100 % AVAILABILITY

| From | To | ➔ | ➔ |
|--------------|---------|-------|-------|
| Denmark West | Germany | 90 % | 100 % |
| Sweden | Germany | 70 % | 55 % |
| Sweden | Poland | 70 % | 55 % |
| Finland | Russia | 100 % | 91 % |
| Finland | Estonia | 79 % | 82 % |

The numbers in Table 5-2, are based on historical (realized) values. This is not the case for the border Denmark West – Germany though, where the cross-border capacities have been adjusted to anticipate the inner German grid reinforcements.

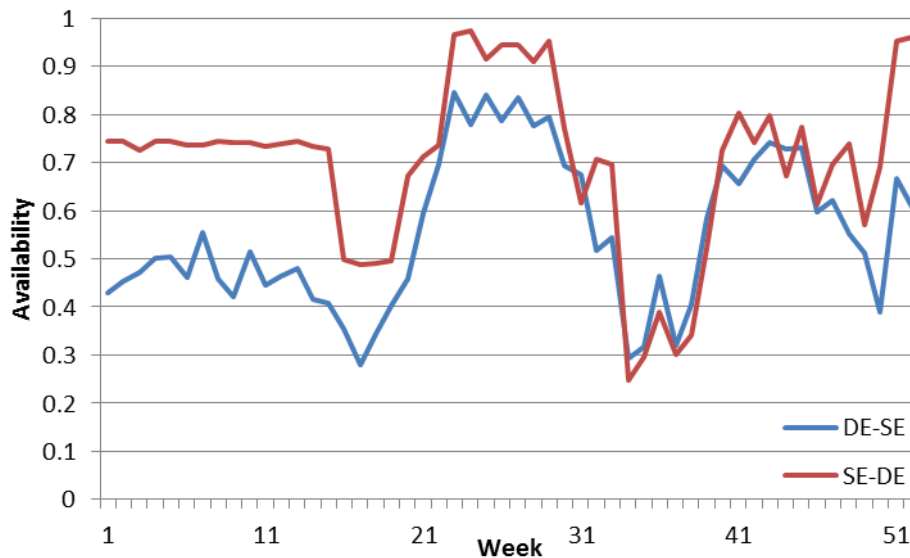


FIGURE 5-4 SEASONAL AVAILABILITY FOR THE INTERCONNECTORS SWEDEN–GERMANY AND SWEDEN–POLAND (SAME PROFILE HAS BEEN USED)

5.1.1 YEAR 2020

Between the years 2015 and 2020, some major changes are expected in the system. In Sweden four nuclear reactors (Oskarshamn 1 and 2, Ringhals 1 and 2) will be decommissioned, while in Finland Olkiluoto 3 will be commissioned. The capacity in wind and solar power is increasing. The installed capacity is presented in Figure 5-5 and Table 5-3.

The demand is expected to increase by a little more than two percent and several new interconnectors will be in operation: Kriegers Flak 400 MW (back-to-back, Eastern Denmark – Germany), and Nord Link 1 400 MW (Norway–Germany).

In 2020, the production according to the scenario is 414 TWh in the Nordic area, with a surplus of 26 TWh as presented in Figure 5-6.

TABLE 5-3 INSTALLED CAPACITIES (MW) IN THE NORDIC COUNTRIES IN 2020

| Fuel | Denmark | Finland | Norway | Sweden |
|------------------|---------------|---------------|---------------|---------------|
| Hydro | 0 | 2 758 | 32 867 | 15 617 |
| Wind | 6 528 | 1 675 | 1 337 | 5 911 |
| Solar | 709 | 117 | 117 | 670 |
| Biomass | 851 | 3 549 | 0 | 3 615 |
| Biomass, pellets | 330 | 145 | 0 | 0 |
| Peat | 0 | 188 | 0 | 0 |
| Waste | 329 | 98 | 0 | 430 |
| Nuclear | 0 | 4 352 | 0 | 6 752 |
| Coal | 2 025 | 1 673 | 0 | 130 |
| Natural Gas | 1 245 | 2 162 | 583 | 390 |
| Light Fuel Oil | 716 | 0 | 0 | 0 |
| Heavy Fuel Oil | 123 | 105 | 0 | 190 |
| Total | 12 856 | 16 822 | 34 904 | 33 706 |

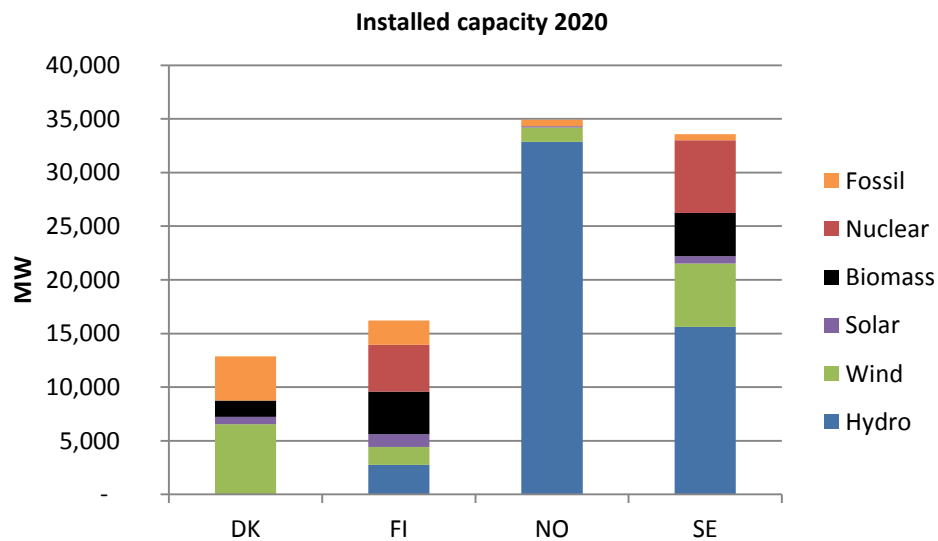


FIGURE 5-5 INSTALLED CAPACITY IN NORDIC COUNTRIES IN 2020. PEAT AND WASTE ARE INCLUDED IN BIOMASS.

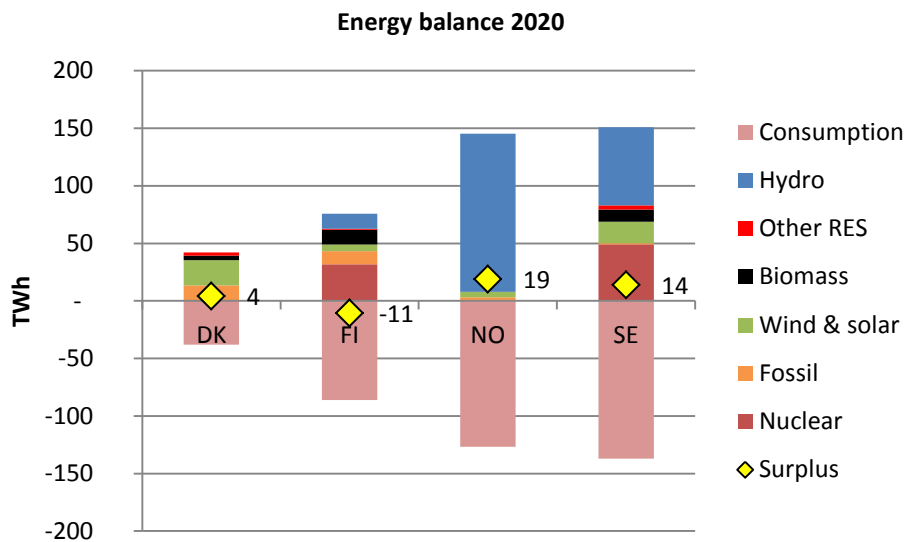


FIGURE 5-6 SIMULATED ENERGY BALANCES FOR THE NORDIC COUNTRIES IN 2020

5.1.2 YEAR 2025

Between 2020 and 2025, Sweden may reach an installed wind capacity of 9 GW, as a result of the political agreement on energy. The capacities are presented in Table 5-4 and Figure 5-7. Additional interconnectors are the North Sea Link 1 400 MW (Norway–England), and the Hansa PowerBridge 700 MW (Sweden–Germany).

The demand in the Nordic area is increasing by approximately six percent during these five years. General drivers for increasing demand are the growing population, electric vehicles, and potential new data centres. In Denmark there are also plans to electrify the railroad, and in Norway to connect off-shore installations to the grid. In 2025, the production according to the scenario is 441 TWh in the Nordic area, with a surplus of 31 TWh as presented in Figure 5-8. The scenario is regarded to be quite robust, hence not very sensitive to minor changes of the assumptions, for both the years 2020 and 2025. Some of the tipping points that could influence the results (although perhaps not the inertia part) are:

- Additional Swedish nuclear reactors being decommissioned before 2020 (Vattenfall recently postponed the decision on additional safety measures on Ringhals 3 & 4 by six months).
- Germany not being able to remove internal bottlenecks according to plan. During January 2017, the availability on the Denmark West – Germany border was <8 %, whereas 90 % is reflected in our scenarios.
- Price on European Union Emission Trading Scheme (EU-ETS; CO₂) jumping high in the next trading period (2021–2028), which might keep some CHPs running in the system, instead of being converted to pure heat providers.
- Prices remaining on the current low level, or even lower, will most probably not lead to more gas-fuelled plants in the Nordics, even if it should be profitable. Decommissioning of fossil-fuelled plants might be postponed.

TABLE 5-4 INSTALLED CAPACITIES (MW) IN THE NORDICS IN 2025.
BETWEEN THE BRACKETS, THE DIFFERENCE COMPARED TO 2020 (TABLE 5-3) IS MENTIONED.

| Fuel | Denmark | Finland | Norway | Sweden |
|------------------|-----------------------|----------------------|-----------------------|-----------------------|
| Hydro | 0 (0) | 2 758 (0) | 32 867 (0) | 15 617 (0) |
| Wind | 8 006 (1 478) | 2 472 (797) | 2 504 (1 167) | 9 195 (3 284) |
| Solar | 1 145 (436) | 503 (386) | 280 (163) | 1 109 (439) |
| Biomass | 1 150 (299) | 3 545 (-4) | 0 (0) | 3 615 (0) |
| Biomass, pellets | 330 (0) | 145 (0) | 0 (0) | 0 (0) |
| Peat | 0 (0) | 188 (0) | 0 (0) | 0 (0) |
| Waste | 299 (-30) | 98 (0) | 0 (0) | 430 (0) |
| Nuclear | 0 (0) | 4 352 (0) | 0 (0) | 6 752 (0) |
| Coal | 1 265 (-760) | 481 (-1 192) | 0 (0) | 130 (0) |
| Natural Gas | 1 127 (-118) | 2 001 (-161) | 583 (0) | 390 (0) |
| Light Fuel Oil | 716 (0) | 0 (0) | 0 (0) | 0 (0) |
| Heavy Fuel Oil | 106 (-17) | 105 (0) | 0 (0) | 190 (0) |
| Total | 14 144 (1 288) | 16 648 (-174) | 36 235 (1 331) | 37 428 (3 722) |

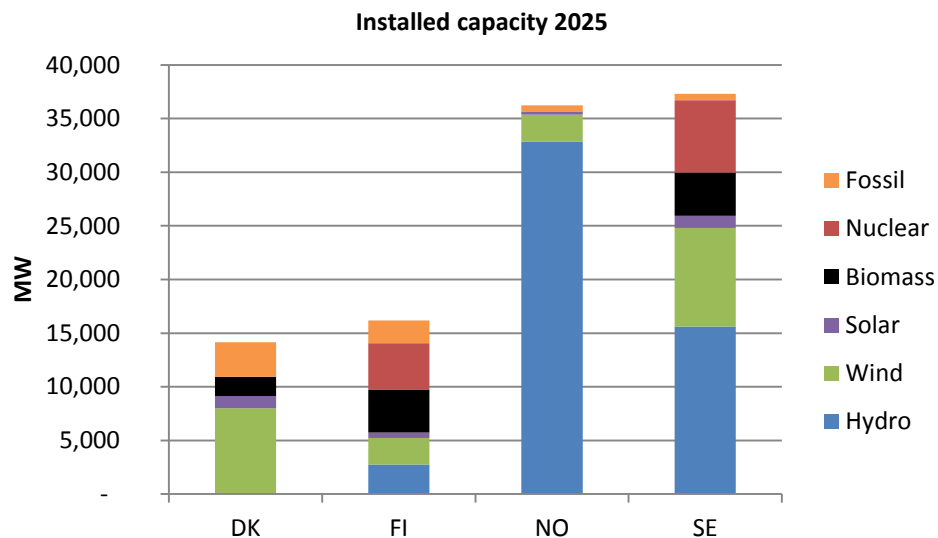


FIGURE 5-7 INSTALLED CAPACITY IN NORDIC COUNTRIES IN 2025. PEAT AND WASTE ARE INCLUDED IN BIOMASS

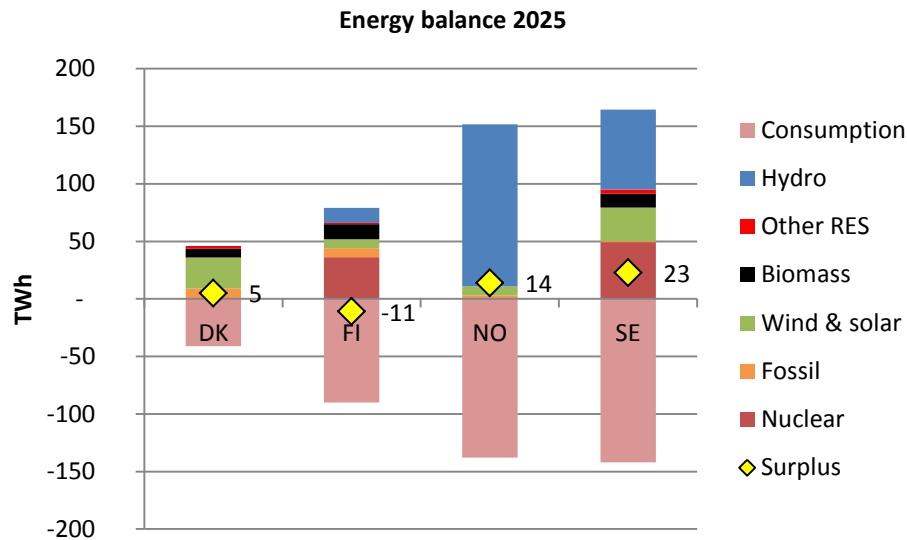


FIGURE 5-8. SIMULATED ENERGY BALANCES FOR THE NORDIC COUNTRIES IN 2025.

5.2 MARKET SIMULATIONS

In this section, the market simulations based on the market scenarios defined – being the second step in the simulation chain in Figure 5-1 – are touched upon. The EFI's Multi-area Power-Market Simulator (EMPS) market model is currently the most accurate market model to describe the Nordic power system. Moreover for accurate inertia estimations it is needed to use a market model with a detailed description of hydro and thermal generators. The EMPS dataset, used in the simulations, models the hydropower with over 1 200 individual units and models all thermal power plants with a capacity over 100 MW individually. The model setup used in this study models the Nordic and Baltic power systems fundamentally, and the connected countries (Germany, Poland, The Netherlands, and Great Britain) are described with fixed prices, see Figure 5-9.

In this study an additional functionality, named SAMLAST, was used. This functionality, schematically described in Figure 5-10, simulates the physical flow in the grid and adds additional restrictions (on top of the given Net Transfer Capacities (NTCs)) to the market results in order to provide feasible physical grid flows, which ensures a more realistic production distribution result.

Previously the model has mainly been used to study annual and weekly average results, however in this study the results from extreme situations is important, and results with a finer resolution are needed. Therefore it was deemed necessary to examine if the model results, on an hourly level, correspond to the reality. In order to test the model performance, the system was simulated in the stage of 2014, and the weather conditions of 2014; the results were then compared with actual 2014 data (see Section 5.4). The years 2020 and 2025 have been simulated with a 3-hour resolution, with the weather conditions of all years from 1980–2012, in order to capture a greater variation of possible conditions (see Section 5.5).

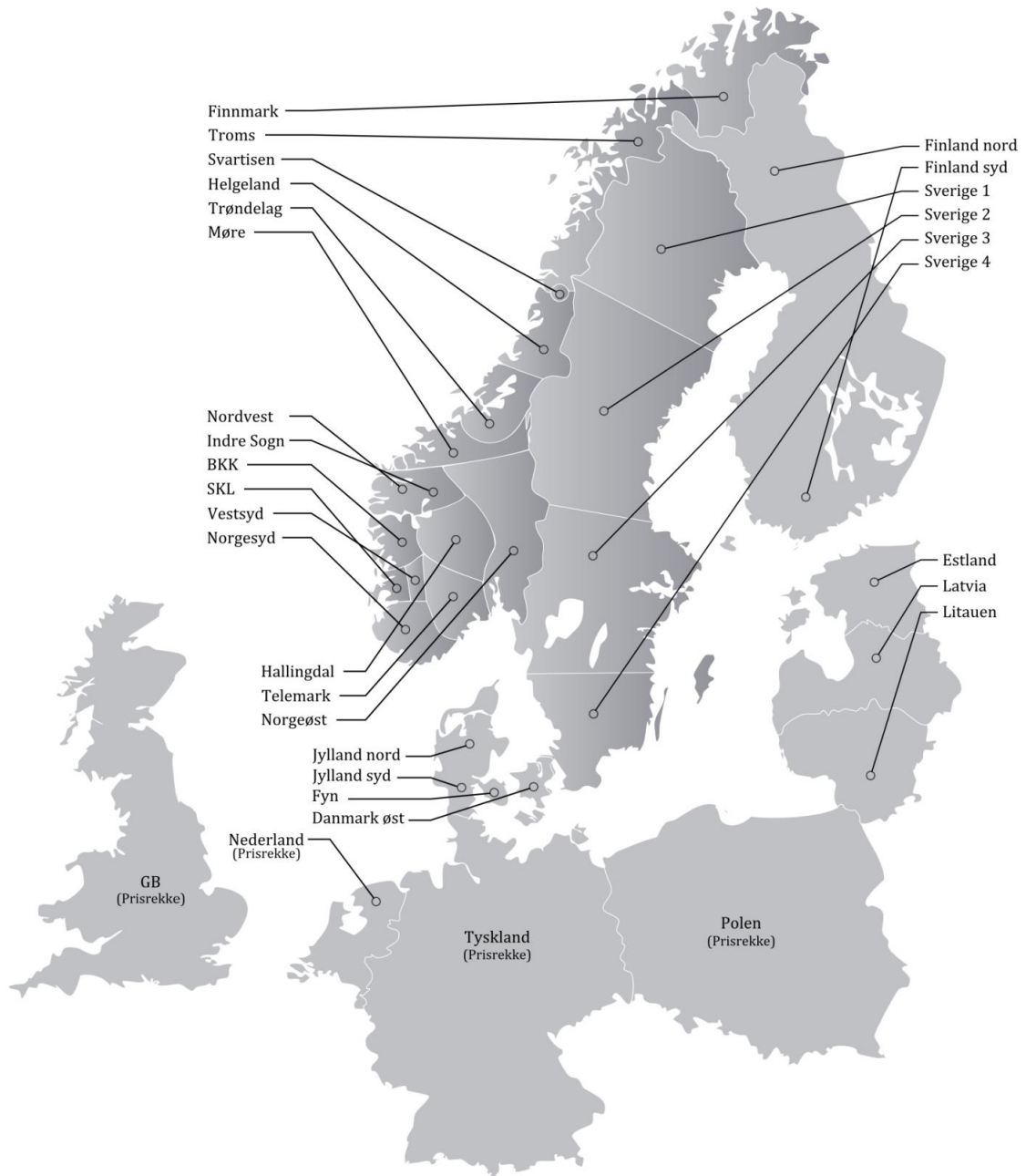


FIGURE 5-9 EMPS MARKET PRICE AREAS

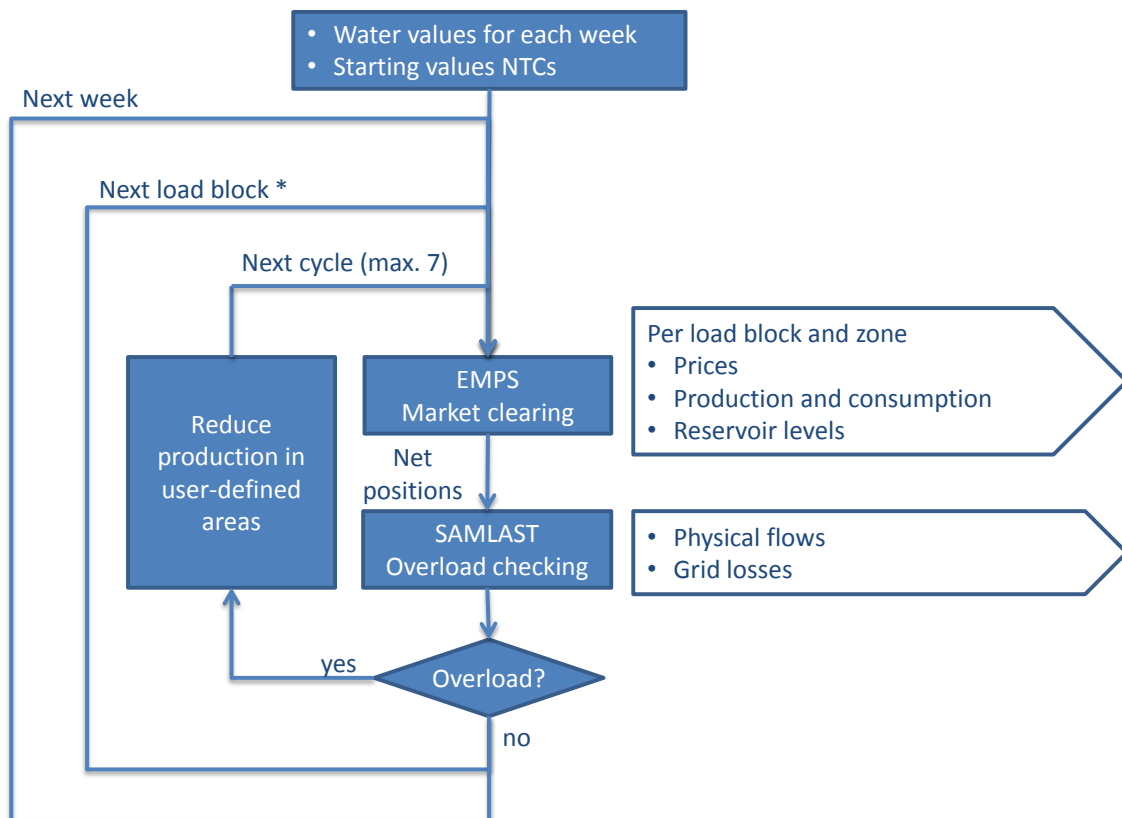


FIGURE 5-10 EMPS AND SAMLAST SIMULATIONS (*56 LOAD BLOCKS PER WEEK HAVE BEEN USED)

5.3 KINETIC ENERGY ESTIMATION

In this last step of the simulation chain, depicted in Figure 5-1, the market simulation results are translated into an estimation of the total kinetic energy in the system.

The approach followed to translate the market simulation results into a kinetic energy estimation is depicted in Figure 5-11, and will be elaborated upon below.

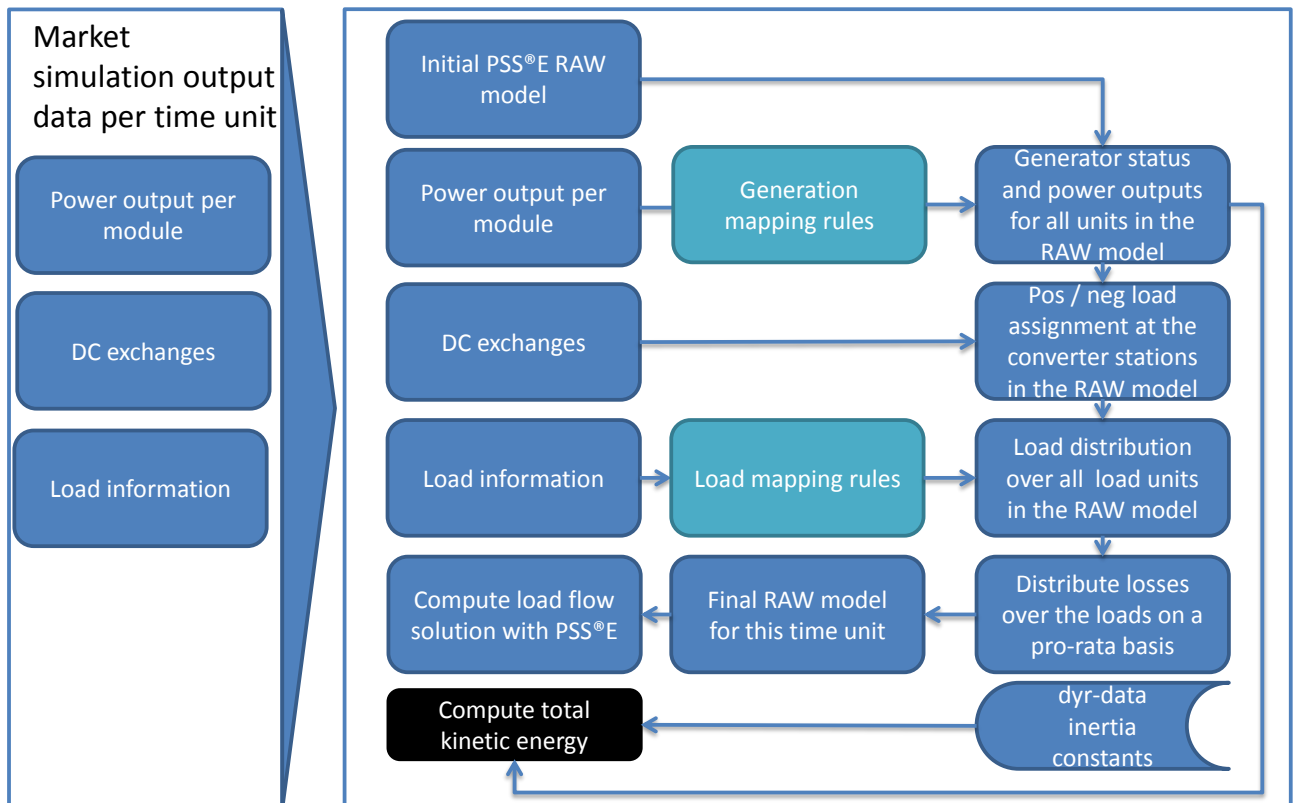


FIGURE 5-11 TRANSLATION OF THE MARKET SIMULATION RESULTS INTO A KINETIC ENERGY ESTIMATION

The process starts from the market simulation results for each time unit for all synchronous Nordic market areas, utilizing in-house developed code to turn each market simulation time unit into a balanced load flow case on a Nordic grid model. Essential for the kinetic energy estimation is actually only the status information of the synchronous generation on each time unit. So instead of producing the complete PSS®E raw dataset of power flow balance for each time unit, and solving the actual load flow, the kinetic energy calculation can be boosted by resolving just the actual synchronous generation mapping for each time unit.

The computation of the kinetic energy is performed by summing the product of the inertia constant and the rated apparent power of each on-line synchronous generator at a given time unit. Most of the turbine-generators' inertia constants and rated apparent powers are readily available from the Nordic grid model datasets. For generating units, where values are missing (e.g. new future scenario units, and especially the category of small-scale hydro "SMAAKRAFT"), generic values are applied.

The advantage of EMPS and SAMLAST models is that the description of the synchronous generation fleet is – especially for hydro – so detailed that there is not so much need for extra decision making on the status of individual generating units. In those cases where generation modules do consist of multiple machines, a conservative approach is taken: a new generation unit is not put on-line until the capacity of already on-line generation is fully utilized. As illustrated in the calibration simulations for the year 2014 (see Section 5.4), this approach seems to give credible estimations of the kinetic energy. Therefore the same procedure is applied for the future

scenario years 2020 and 2025, with the exception that instead of a single hydro year, a series of 33 hydro years – from 1980 to 2012 – is used, with a 3-hour time resolution. This produces a total of 96 096 (= $(24/3) \times 364 \times 33$) rounds of total kinetic energy value calculations for each scenario year.

5.4 SIMULATION CHAIN BACK TESTING

To test if the simulation chain in Figure 5-1 provides a valid approach for the future kinetic energy estimation, a back testing has been performed on the year 2014.

Where the consumption and RES infeed have been used as an input, the focus is on the production results, namely hydro and thermal. To examine this, the duration curves for hydro and other thermal production were studied to ensure that the frequency of situations with low production corresponds to reality. The seasonal pattern was also studied, to ensure that the seasonal pattern of production - and inertia - is representative.

The duration curves in Figure 5-12 and Figure 5-13 indicate that both hydro and thermal production levels are well represented in the model. On the most interesting part, namely the lower end of the duration curve, one can see that the amount of hydro production is somewhat overestimated and the amount of thermal production is underestimated in the model.

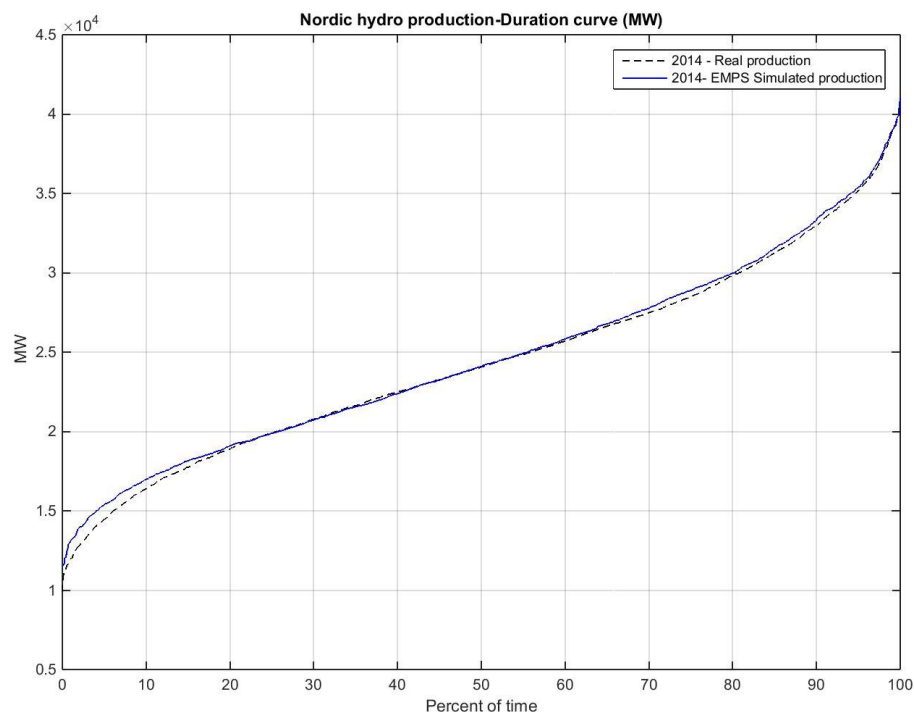


FIGURE 5-12 NORDIC HYDRO PRODUCTION 2014 – SIMULATION RESULTS COMPARED WITH HISTORICAL DATA

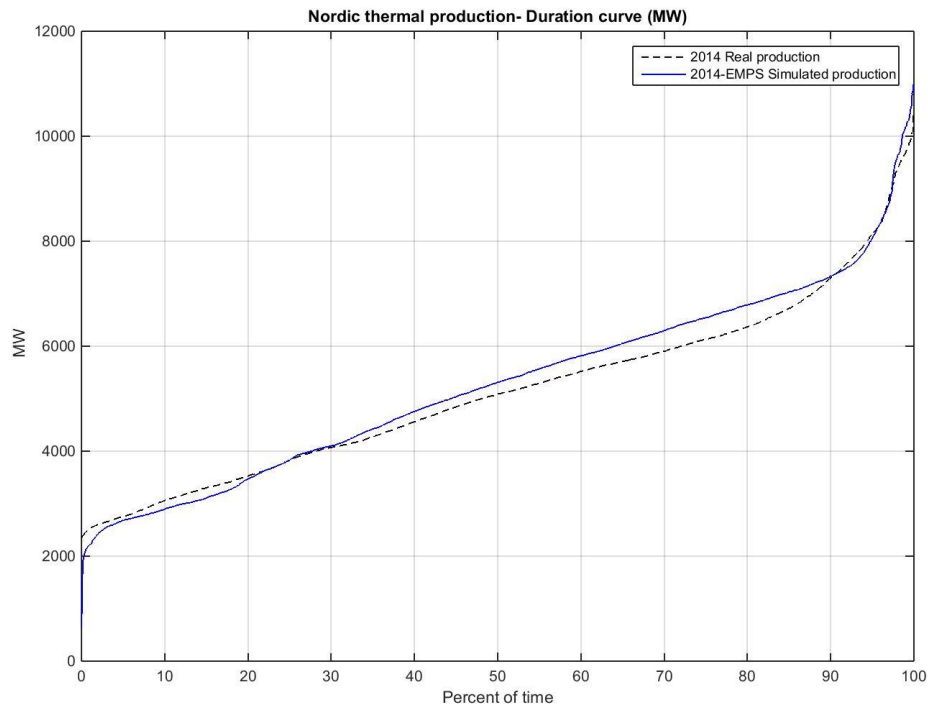


FIGURE 5-13 NORDIC THERMAL PRODUCTION 2014 – SIMULATION RESULTS COMPARED WITH HISTORICAL DATA

The resulting weekly minimum values for hydro and thermal are shown in Figure 5-14 and Figure 5-15 below. In general, the seasonal behaviour of the minimum production for both hydro and thermal is rather well represented in the model. In the summer season, the model overestimates the minimum hydro production and underestimates the minimum thermal production. This is due to the fact that start-up costs and reserve requirements are not included in the model, which results in thermal units to stop for short periods - when their marginal cost is higher than the electricity price - whereas in reality they would run to save start-up cost, or to act as reserves.

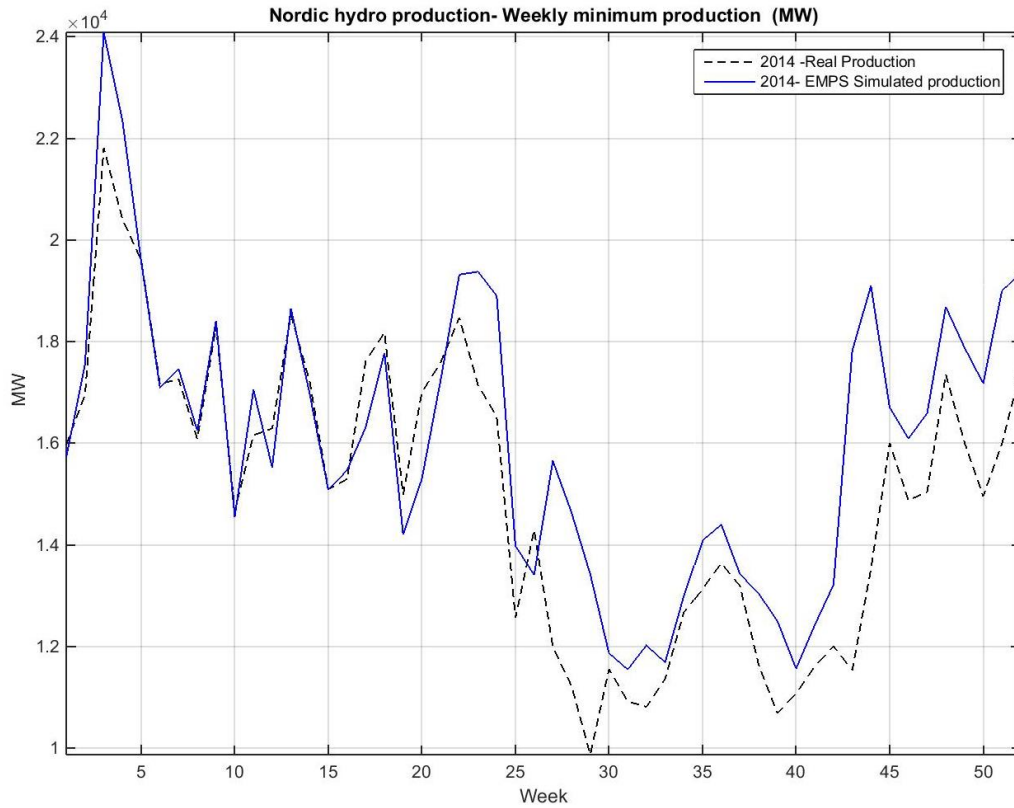


FIGURE 5-14 WEEKLY MINIMUM HYDRO PRODUCTION IN THE NORDIC POWER SYSTEM

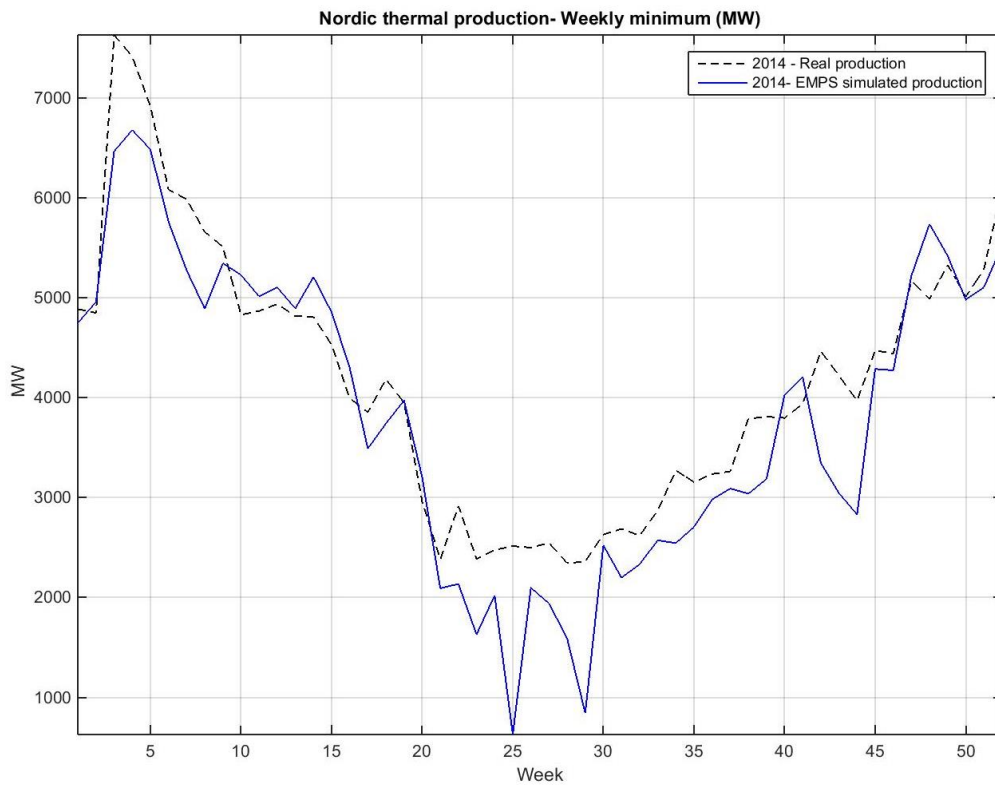


FIGURE 5-15 WEEKLY MINIMUM THERMAL (NON-NUCLEAR) PRODUCTION IN THE NORDIC POWER SYSTEM

The monitored and computed kinetic energy are shown in Figure 5-16. When for the small-scale hydro generation (“SMAAKRAFT”), a $H = 0$ s is applied – indeed, the smaller units are not monitored in the SCADA systems –, the monitored and computed kinetic energy values coincide, which confirms the validity of the simulation approach.

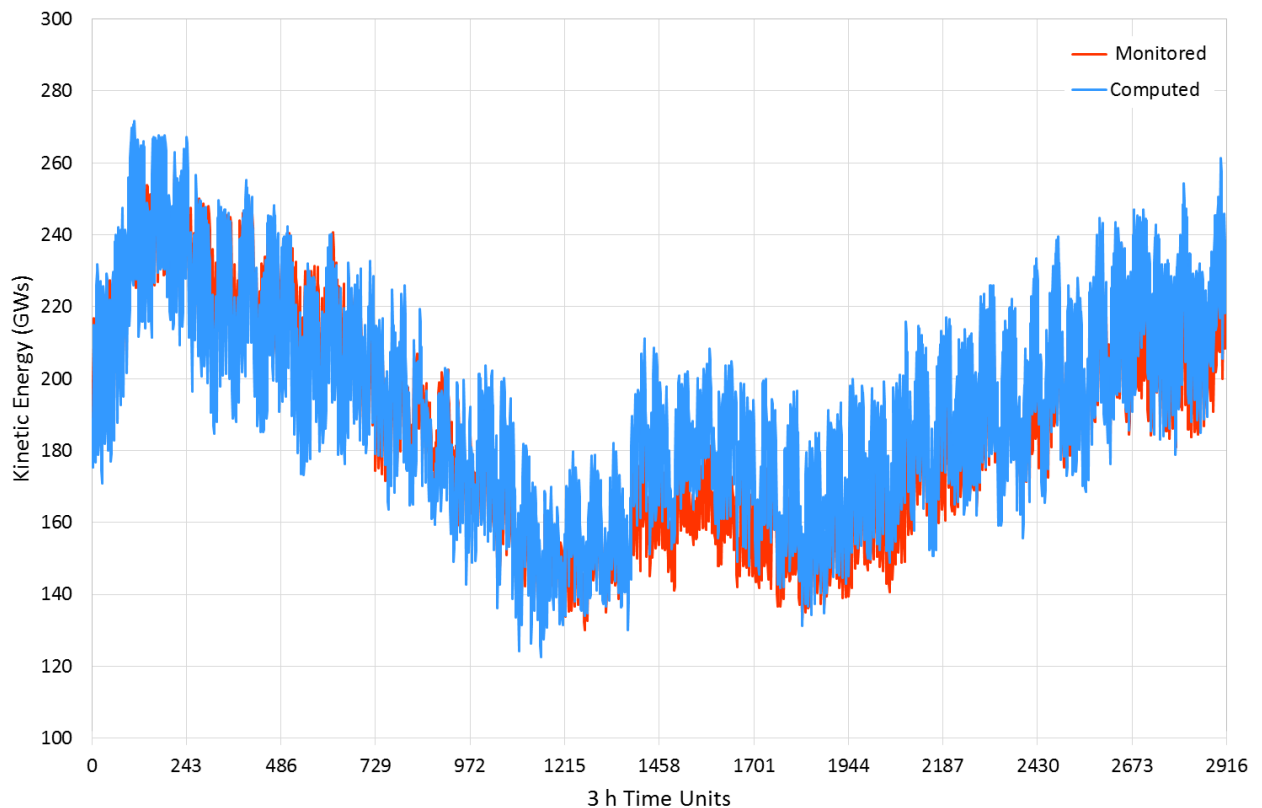


FIGURE 5-16 COMPUTED KINETIC ENERGY ESTIMATE COMPARED TO MONITORED VALUES FOR THE YEAR 2014 IN THE NORDIC SYSTEM

In the 2020 and 2025 kinetic energy computations, a value of $H = 1$ s for the small-scale hydro generation (“SMAAKRAFT”) has been applied (the same value was used in the inertia 1 project [2]).

5.5 KINETIC ENERGY ESTIMATIONS FOR THE YEARS 2020 AND 2025

In the following, the results of the kinetic energy computations for 2020 and 2025 are presented in the form of two pairs of graphs, each representing one study year to facilitate an easy comparison. The first pair of graphs presents the full time series of the calculated kinetic energy values for all 33 hydro years, projected on one annum: the yellow curve is the average value of the kinetic energy values of the 33 simulated years, whereas the grey curve shows the minimum and maximum values. The red line highlights the 120 GWs value.

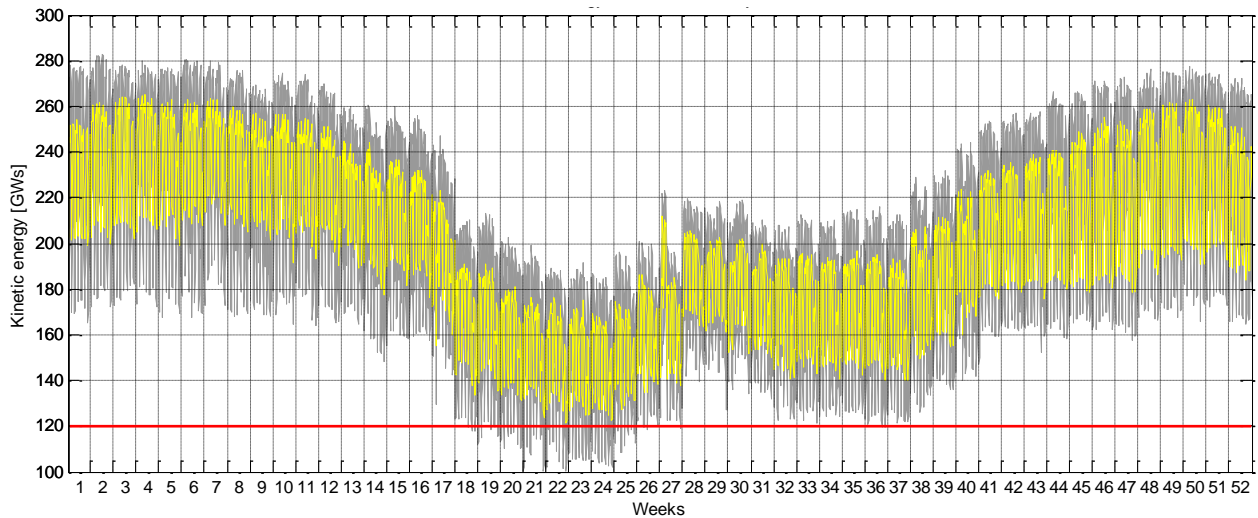


FIGURE 5-17 KINETIC ENERGY ESTIMATION OF THE YEAR 2020

THE YELLOW CURVE IS THE AVERAGE VALUE OF THE KINETIC ENERGY VALUES OF THE 33 SIMULATED YEARS, WHEREAS THE GREY CURVE SHOWS THE MINIMUM AND MAXIMUM VALUES. THE RED LINE HIGHLIGHTS THE 120 GWs VALUE.

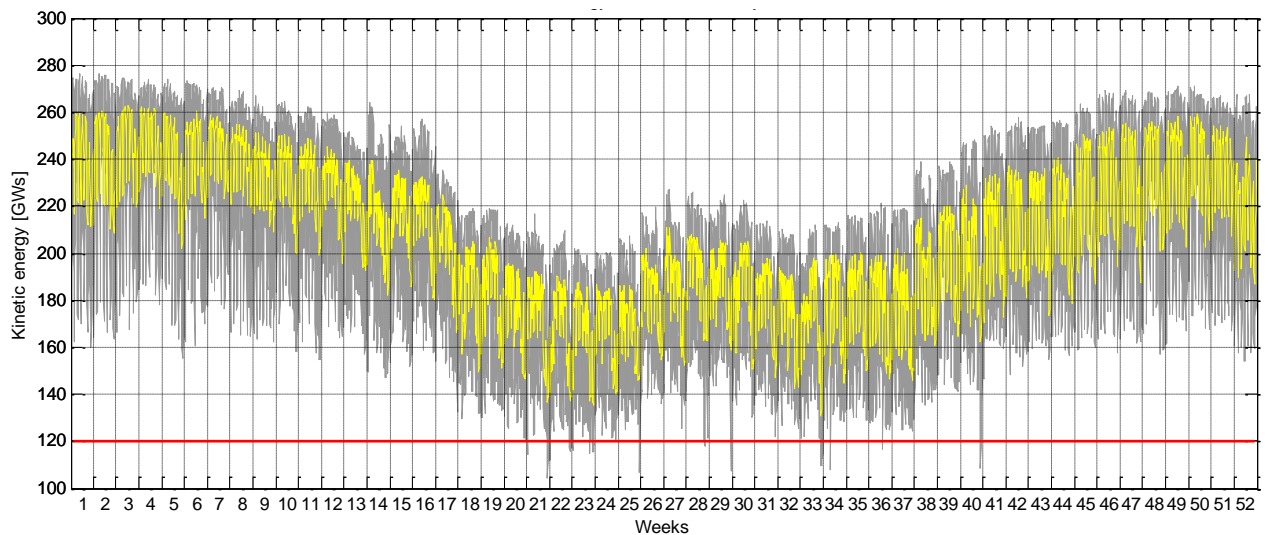


FIGURE 5-18 KINETIC ENERGY ESTIMATION OF THE YEAR 2025

THE YELLOW CURVE IS THE AVERAGE VALUE OF THE KINETIC ENERGY VALUES OF THE 33 SIMULATED YEARS, WHEREAS THE GREY CURVE SHOWS THE MINIMUM AND MAXIMUM VALUES. THE RED LINE HIGHLIGHTS THE 120 GWs VALUE.

We can see from Figure 5-17 and Figure 5-18, that in the year 2025 the total variation in kinetic energy values is smaller than in 2020: the minimum values are higher than in 2020, and the maximum values are lower than in the year 2020.

The second pair of figures zooms in to the lower end of the duration curves of the kinetic energy values of the years 2020 and 2025.

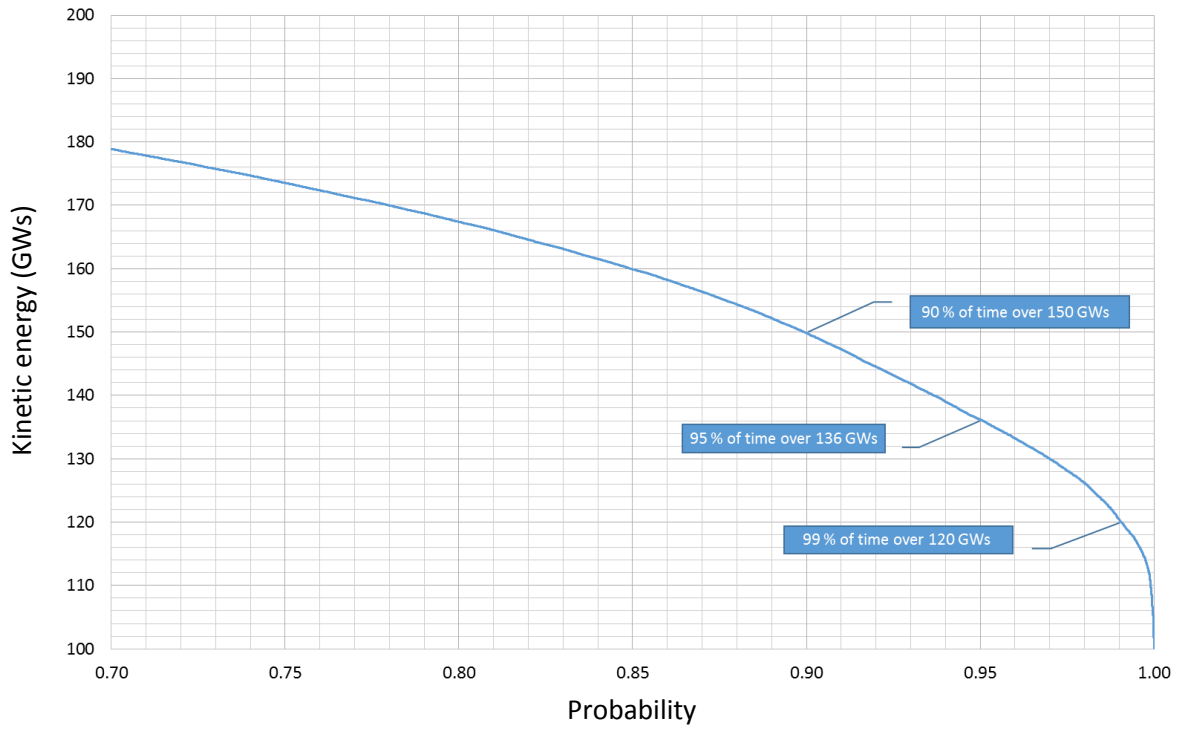


FIGURE 5-19 DURATION CURVE OF THE ESTIMATED KINETIC ENERGY VALUES FOR THE YEAR 2020

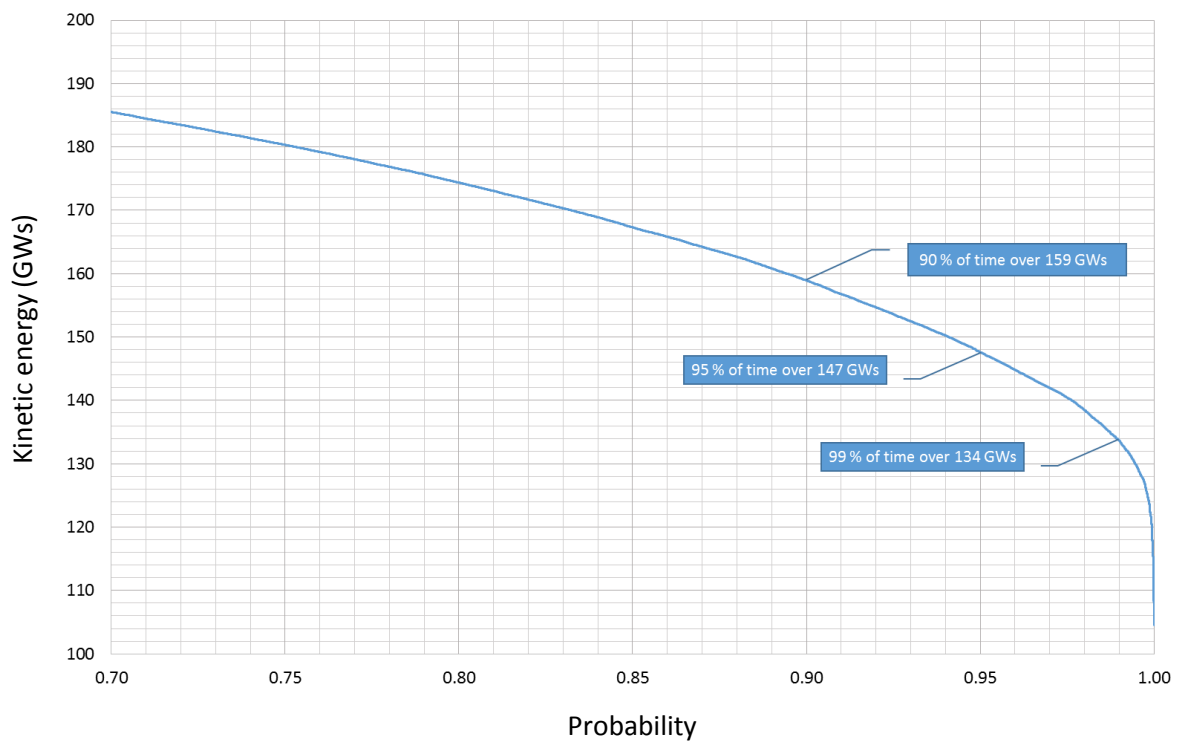


FIGURE 5-20 DURATION CURVE OF THE ESTIMATED KINETIC ENERGY VALUES FOR THE YEAR 2025

From the Figure 5-19 and Figure 5-20, one can see that the increase of kinetic energy at the 90 %, 95 % and 99 % points is around 10 GWs from 2020 to 2025.

The probability of low-kinetic energy values for the two years 2020 and 2025 have been compared to that of the year 2014 (that has been used for the back-testing purposes, as described in Section 5.4). This is depicted in Figure 5-21; note that next to 2014 (2014Comp) and the base scenarios for 2020 and 2025 (2020Base and 2025Base) two additional scenarios, that are elaborated upon in Section 5.5.2, are displayed in the graph (2020LowNuc: nuclear generation capacity in Sweden has been further decreased in scenario 2020 by shutting down two units in Ringhals. 2025NoUK: a new 1 400 MW HVDC link to UK is postponed in the 2025 scenario). When reading the Figure 5-21, please keep in mind that the 2020 and 2025 traces reflect a result covering 33 inflow years, whereas the 2014 trace is based on the 2014 inflow data only. All numbers do originate from kinetic energy computations based on market simulations; such in order to compare similar numbers.

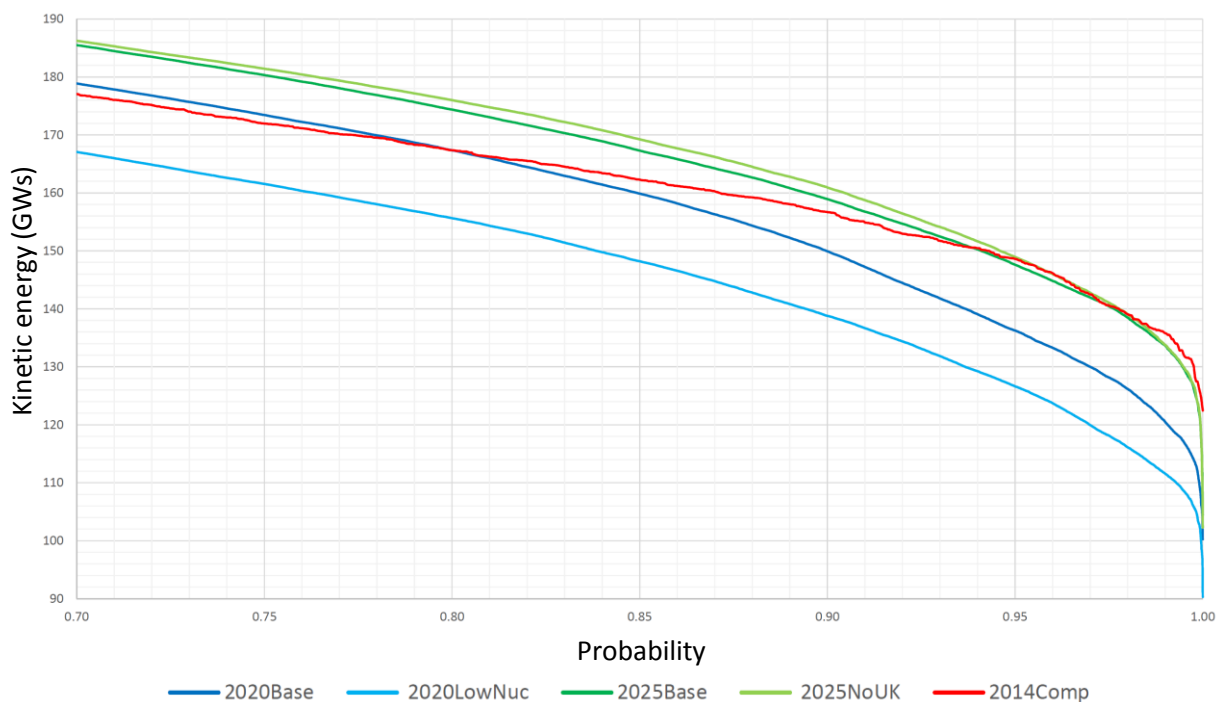


FIGURE 5-21 PROBABILITY OF LOW KINETIC ENERGY VALUES FOR THE YEARS 2014 (2014COMP), 2020 (2020BASE), AND 2025 (2025BASE) COMPARED. TWO ADDITIONAL SCENARIOS, THAT ARE ELABORATED UPON IN SECTION 5.5.2, ARE DISPLAYED IN THE GRAPH: 2020LOWNUC AND 2025NOUK.

The duration of low-kinetic energy dips, i.e. values below the selected 120 GWs threshold value, has been analysed from the time series of the years 2020 and 2025. The results are shown in Table 5-5.

TABLE 5-5 THE NUMBER AND DURATION OF KINETIC ENERGY DIPS BELOW 120 GWs ON SIMULATED RESULTS 2020 AND 2025
ONE TIME UNIT REFERS TO A BLOCK OF 3-HOURS, BEING THE TIME RESOLUTION USED IN THE MARKET SIMULATIONS.

| Dip length [time units] | 2020 [number of dips] | 2025 [number of dips] |
|------------------------------------|----------------------------------|----------------------------------|
| 1 | 146 | 10 |
| 2 | 253 | 8 |
| 3 | 29 | 2 |
| 4 | 16 | 1 |
| 5 | 9 | 1 |
| 6 | 5 | 1 |
| 7 | 0 | 2 |
| 8 | 0 | 0 |
| 9 | 0 | 0 |
| 10 | 1 | 0 |
| 11 | 1 | 0 |

The low-kinetic energy value dips are typically 1–3 time units long, with a maximum length of 11 time units. Please bear in mind, that both 2020 and 2025 have been analysed by using 33 inflow years, with a time resolution (i.e. time unit) of 3 hours.

The simulation results, reflected in the figures and the table, indicate that low-inertia situations (below 120 GWs) will occur in the 2020 and 2025 Nordic power system; the number of hours where this occurs, seems to be limited though. This also has an impact on the mitigation measures to handle low-kinetic energy situations, described in Chapter 8; the limited number of low-inertia hours does not provide a sound basis for introducing a market for these mitigation measures.

5.5.1 ZOOM ON THE EXTREME HYDRO YEARS

To illustrate the impact of dry and wet years on the kinetic energy, the minimum and maximum hydro generation years of the time period 1980–2012 have been selected. For the Nordic countries the minimum hydro year is 1996, and the maximum hydro year is 2012. The comparison is shown below, for both the scenarios 2020 and 2025.

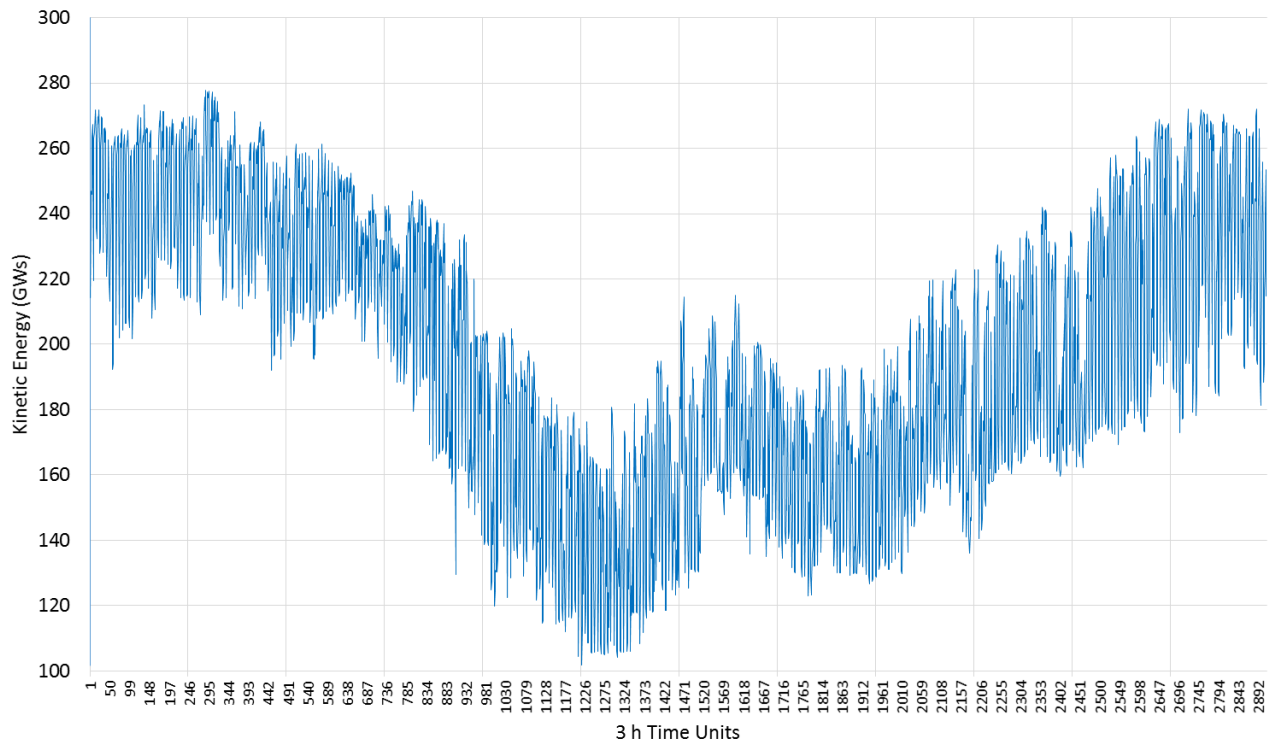


FIGURE 5-22 KINETIC ENERGY FOR SCENARIO 2020 IN THE HYDRO YEAR 1996 (HYDRO GENERATION 180.5 TWH)

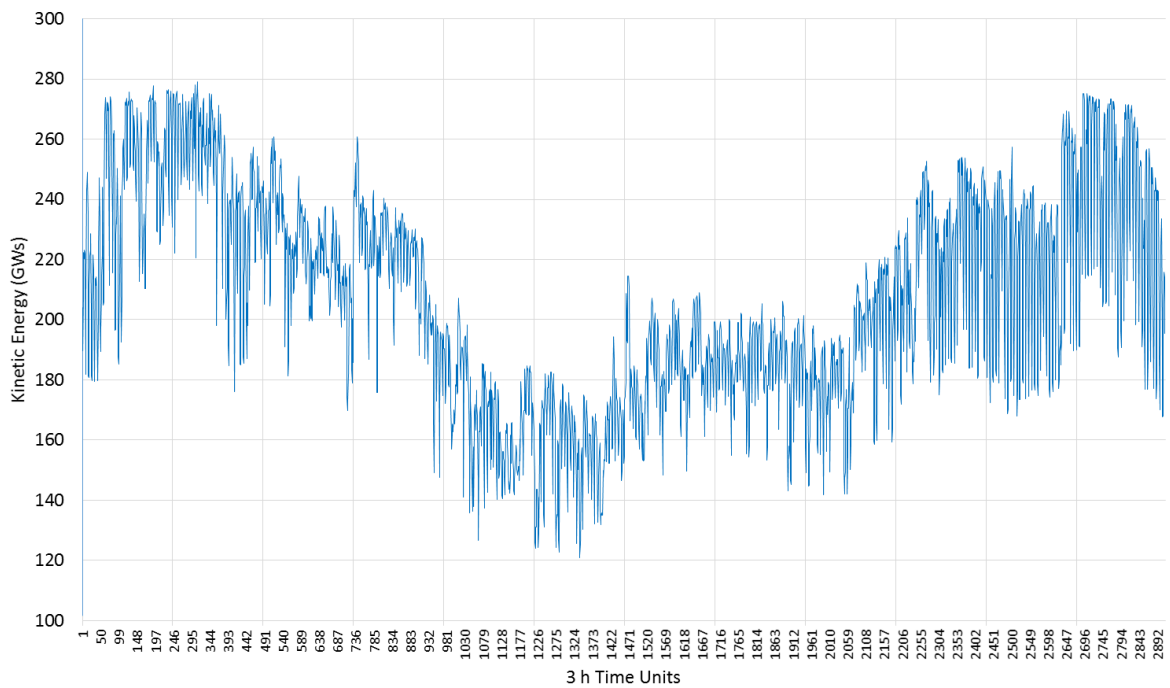


FIGURE 5-23 KINETIC ENERGY FOR SCENARIO 2020 IN THE HYDRO YEAR 2012 (HYDRO GENERATION 245.8 TWH)

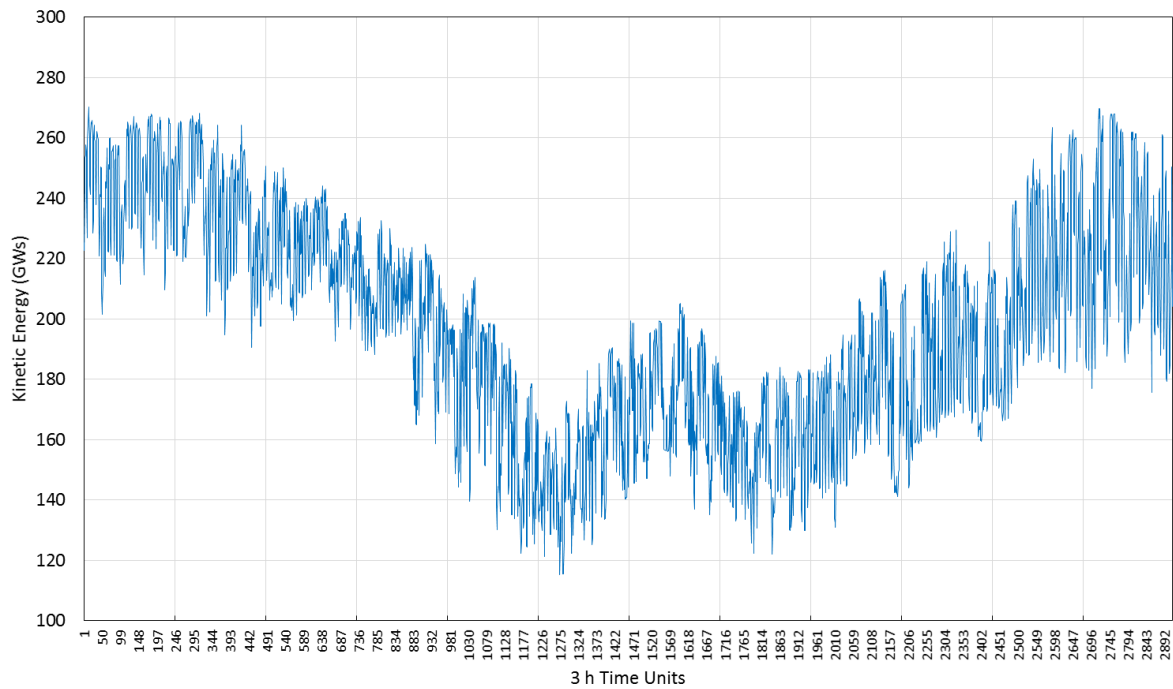


FIGURE 5-24 KINETIC ENERGY FOR SCENARIO 2025 IN THE HYDRO YEAR 1996 (HYDRO GENERATION 176.1 TWH)

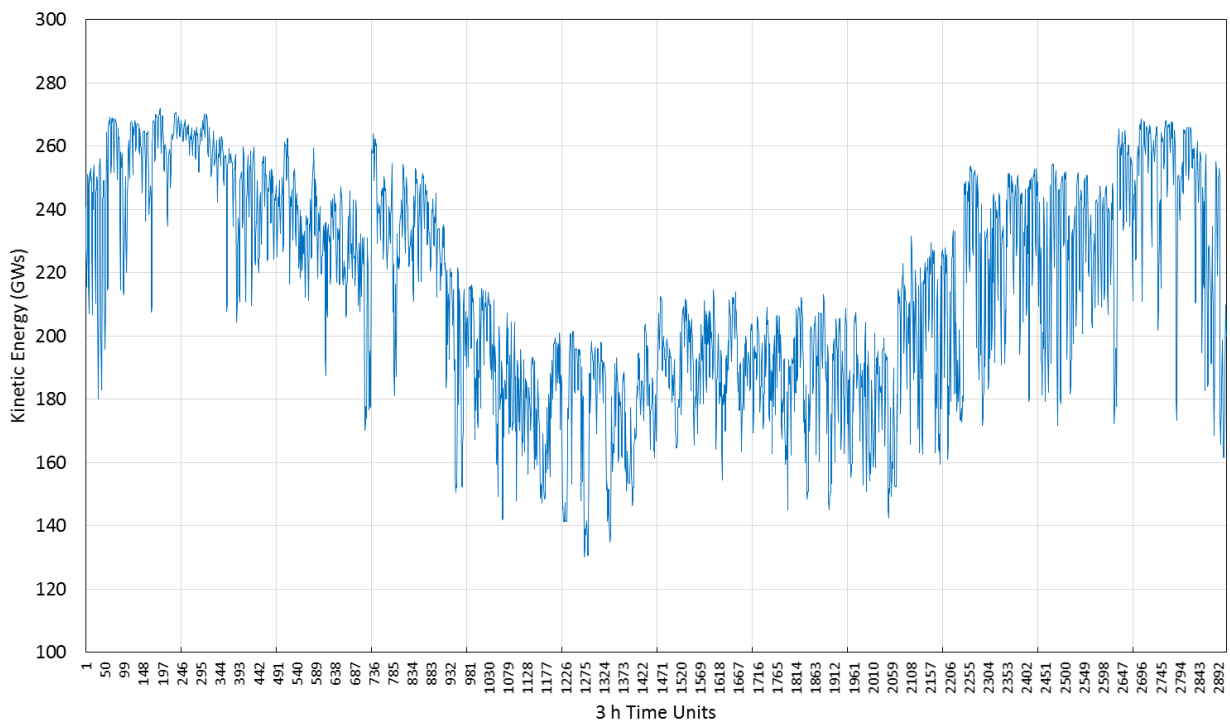


FIGURE 5-25 KINETIC ENERGY FOR SCENARIO 2025 IN THE HYDRO YEAR 2012 (HYDRO GENERATION 257.8 TWH)

Especially the short-term variation of the total kinetic energy catches the eye: for the minimum hydro year the volatility of the kinetic energy is larger compared to that in the maximum hydro year. A difference in the annual minimum kinetic energy value may also be observed.

The hydro generation in the simulation runs of scenario 2020, has been compared with the historical data of the time period 2011–2016. The results are shown in the form of duration curves in Figure 5-26.

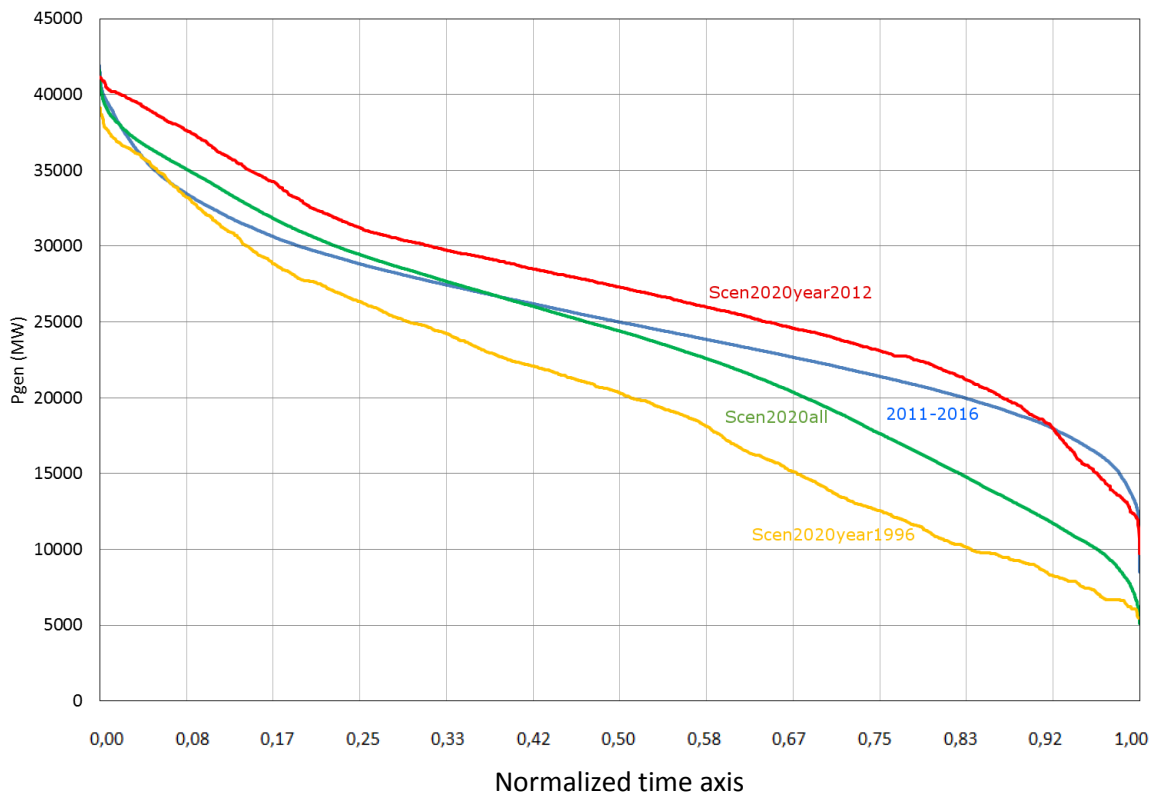


FIGURE 5-26 DURATION CURVE OF THE ACTUAL NORDIC HYDRO GENERATION IN 2011–2016 (BLUE), COMPARED TO THE SIMULATED HYDRO GENERATION IN 2020 (GREEN CURVE ‘SCEN2020ALL’ FOR ALL HYDRO YEARS, YELLOW CURVE ‘SCEN2020YEAR1996’ FOR THE MINIMUM HYDRO YEAR 1996, AND THE RED CURVE ‘SCEN2020YEAR2012’ FOR THE MAXIMUM HYDRO YEAR 2012)

Figure 5-26 confirms the observation that – compared to the present operational experience of the Nordic hydro generation – the market model simulations of the 2020 scenario with EMPS and SAMLAST lead to lower hydro generation levels.

5.5.2 SENSITIVITY STUDIES OF THE SCENARIOS 2020 AND 2025

To test the robustness of the 2020 and 2025 scenario results, two additional sensitivity cases have been simulated. In the first sensitivity case, nuclear generation capacity in Sweden has been further decreased in scenario 2020 by shutting down two units in Ringhals. In the second sensitivity case it is assumed that a new 1 400 MW HVDC link to UK is postponed in the 2025 scenario.

Low nuclear sensitivity compared to base scenario 2020

The kinetic energy computation has been repeated for all 33 hydro years in the 2020 scenario, assuming the nuclear units Ringhals 3 and 4 to be shutdown compared to the base scenario (Section 5.1.1). The comparison of the kinetic energy duration curves is shown in Figure 5-27.

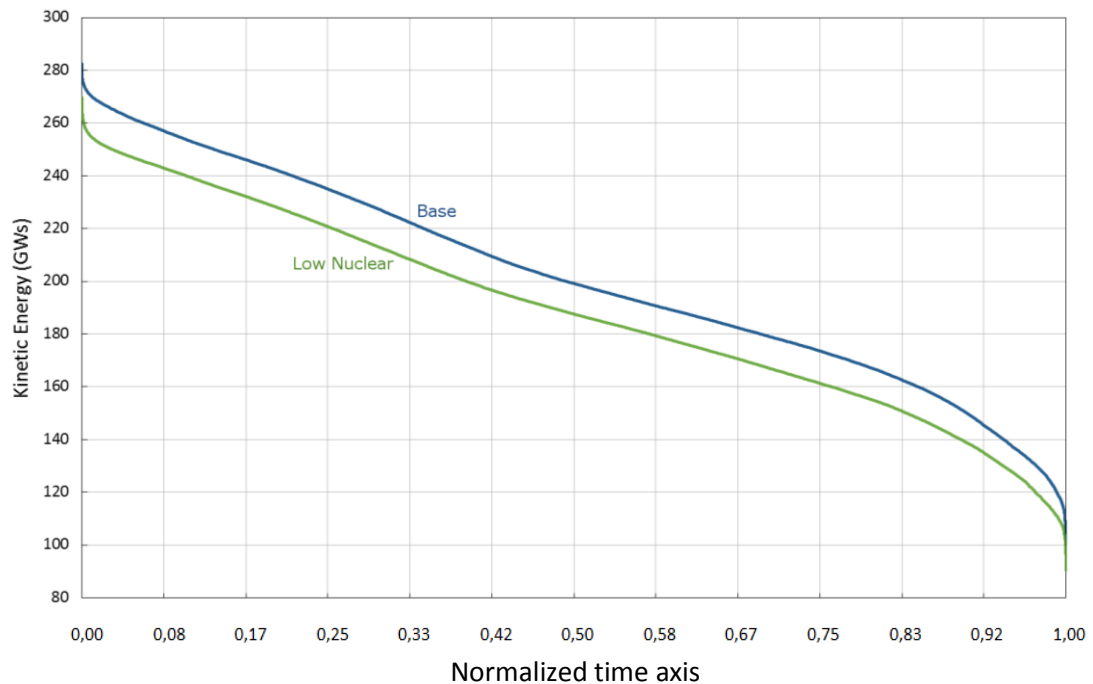


FIGURE 5-27 KINETIC ENERGY DURATION CURVES OF THE “LOW-NUCLEAR” SENSITIVITY CASE AND THE BASE CASE IN SCENARIO 2020

A quite clear and steady 10–15 GWs lower kinetic energy level in the low-nuclear sensitivity case can be seen. This is well in line with the fact that those two base-load nuclear units of Ringhals represent some 16 GWs kinetic energy in total. In the low-nuclear scenario case, the 90 %, 95 %, and 99 % values of the kinetic energy are about 139 GWs, 126 GWs, and 111 GWs respectively. In comparison to the base scenario these values are roughly 10 GWs lower.

No HVDC link to the United Kingdom compared to base scenario 2025

The computation has been repeated for all 33 hydro years in the 2025 scenario (Section 5.1.2), where the 1 400 MW HVDC connection from Norway to the UK is considered to be delayed and not in service. A comparison of the duration curves of the kinetic energy is plotted in Figure 5-28.

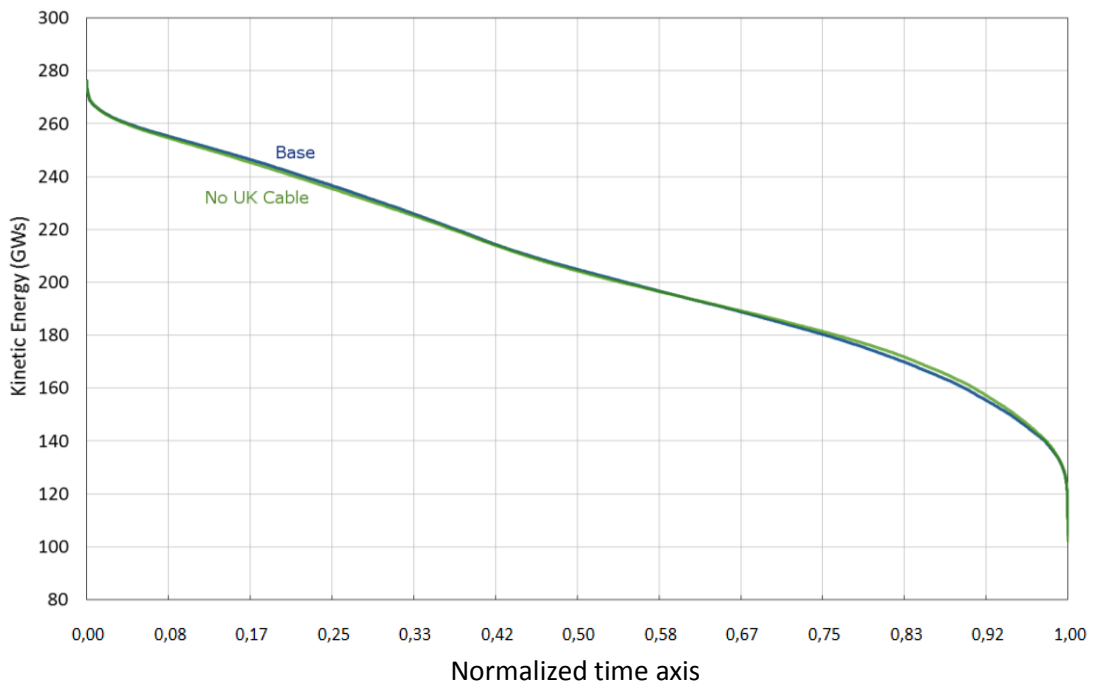


FIGURE 5-28 KINETIC ENERGY DURATION CURVES OF THE “NO UK HVDC CABLE” SENSITIVITY CASE AND THE BASE CASE IN SCENARIO 2025

The difference between the two duration curves in Figure 5-28 is only very subtle.

5.5.3 MINIMUM KINETIC ENERGY STUDIES OF SCENARIOS 2020 AND 2025

When analysing the results from the kinetic energy estimation, it is clear that the inertia is higher in scenario 2025 compared to 2020. This result is, at a first glance, a bit surprising since one can assume the inertia to be lower in the future with a higher share of inverter-based production. To find the reason behind the increased inertia in 2025, a study was made to compare the different results of the simulations. In Figure 5-29 four types of duration curves are shown for both the 2020 and 2025 scenarios. The graphs also indicate the low-inertia operation points, when the kinetic energy is below 110 GWs, in order to quantify the variable relevance.

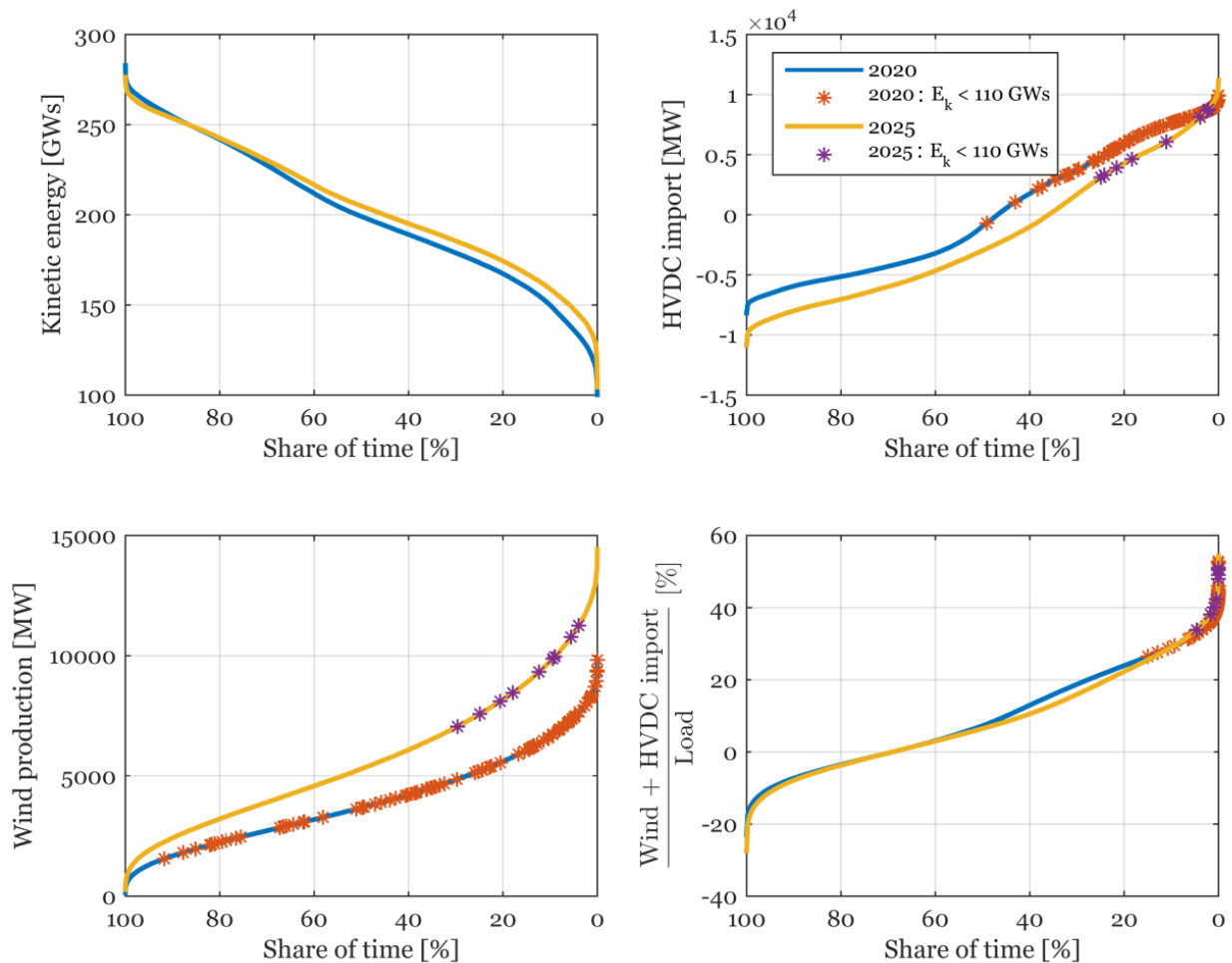


FIGURE 5-29 DURATION CURVES FOR KINETIC ENERGY, TOTAL WIND PRODUCTION, HVDC IMPORT, AND NON-SYNCHRONOUS GENERATION (TOTAL WIND PRODUCTION AND HVDC IMPORT, DIVIDED BY THE SYSTEM LOAD) IN THE NORDIC SYNCHRONOUS AREA

From the figure, the kinetic energy is seen to be lower in 2020 compared to 2025. The wind production is higher in 2025 but still there are more occasions of low kinetic energy in 2020. The low kinetic energy occasions are distributed over the whole curve for 2020, indicating that the wind production alone is not a critical indicator of low kinetic energy. When instead studying the HVDC import, and especially combined wind production and HVDC import relative to the system load, one can see all low-inertia marks in the same area. This indicates that when the load is supplied from a high share of non-synchronous production (wind and HVDC), there is a high probability of low inertia. The question why the kinetic energy is higher in 2025 remains unanswered though.

Figure 5-30 shows both the duration curves of the system load and the kinetic energy from nuclear production.

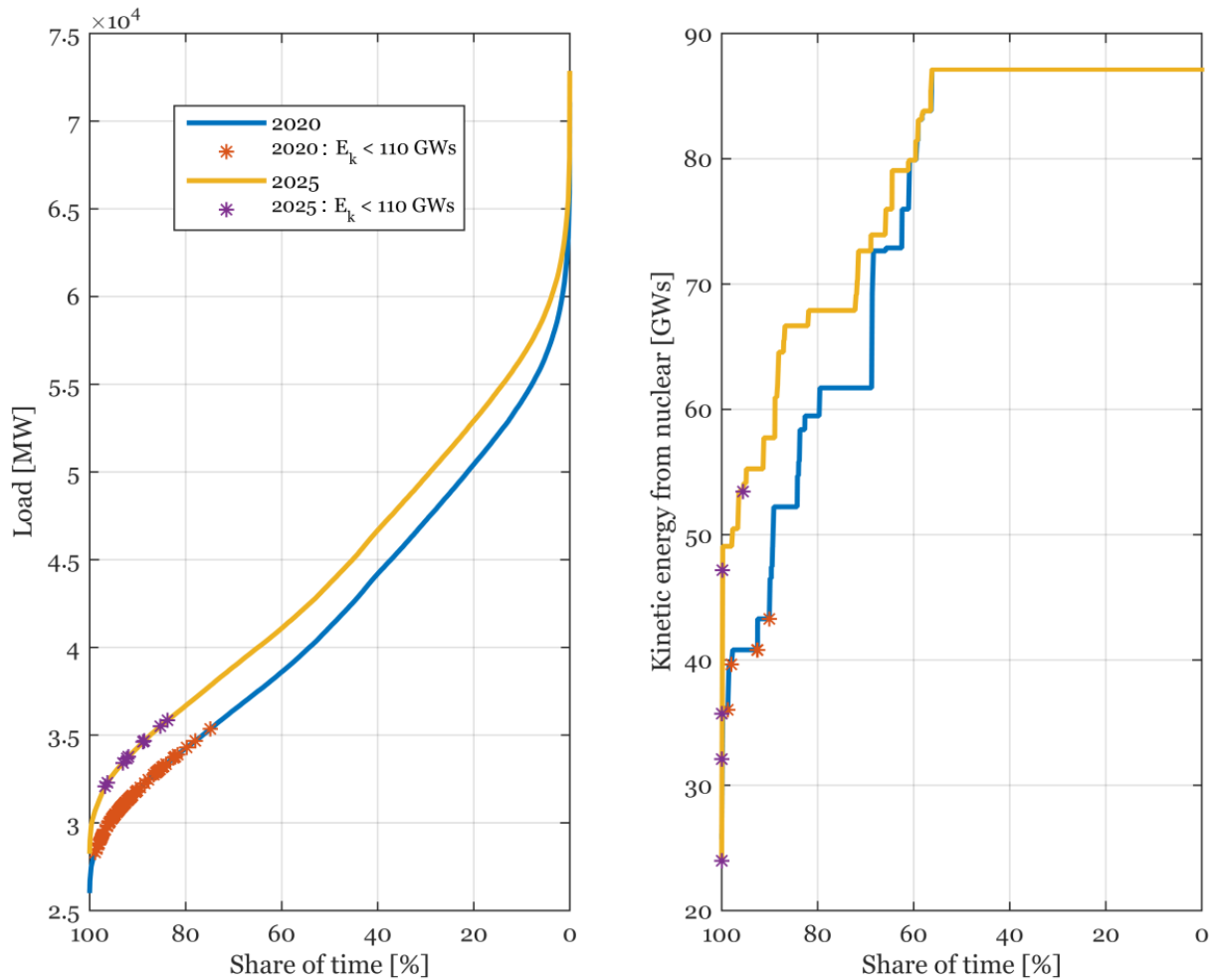


FIGURE 5-30 DURATION CURVES OF SYSTEM LOAD AND KINETIC ENERGY FROM NUCLEAR IN THE NORDIC SYNCHRONOUS AREA

In almost the entire duration curve, scenario 2025 has approximately 2 500 MW more system load compared to 2020. The increased load requires more production, and not all is covered by wind and import. That also results in more synchronous production and thereby higher inertia. Another explanation to the increased inertia in 2025, is the kinetic energy from nuclear. Kinetic energy from nuclear is higher in 2025, even when the total installed kinetic energy is the same for both scenarios. One explanation to this is the availability of Olkiluoto 3. In 2020, the availability profile is assumed to be reduced compared to 2025, see Figure 5-31.

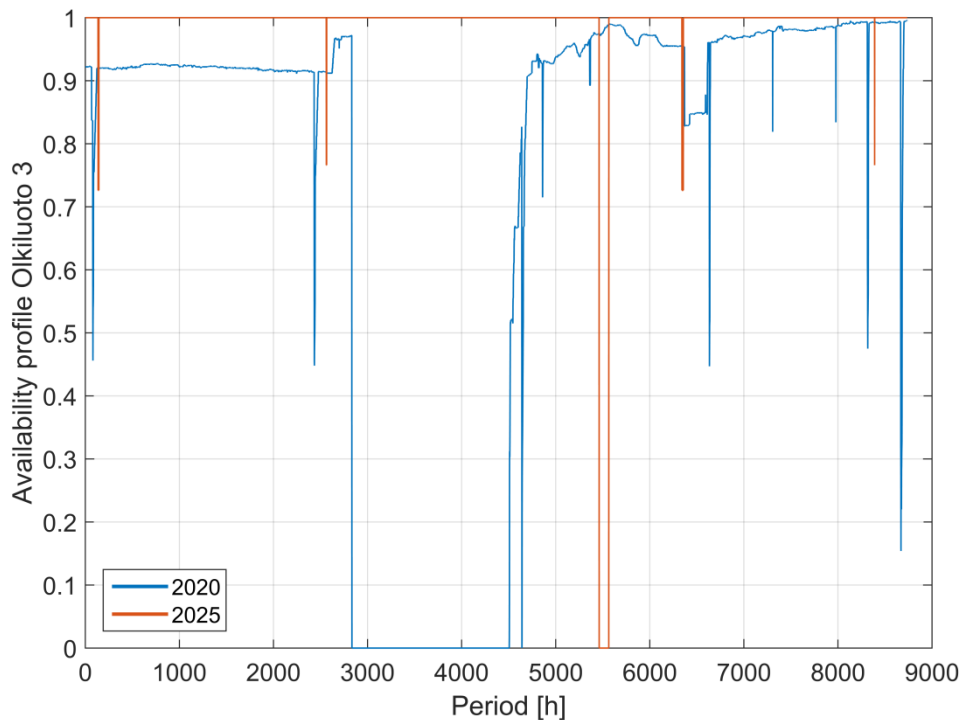


FIGURE 5-31 AVAILABILITY PROFILE OF OLKILUOTO 3 FOR SCENARIO 2020 AND 2025

During the summer time in 2020, Olkiluoto 3 is assumed to be not available and that is a reason contributing to the explanation why the kinetic energy is lower in 2020 compared to 2025.

To further study the simulation results, the dimensioning incident in every simulation period is identified. The dimensioning incident is, in this study, defined as the single largest possible disturbance. In Figure 5-32 and Figure 5-33 the dimensioning incident is plotted as a function of the kinetic energy after the disturbance. In case the dimensioning incident is a nuclear power plant, the kinetic energy will also reduce if this unit is tripped. If the dimensioning incident is an HVDC-link instead, the kinetic energy is not affected by the disturbance. In the same figure both the current and possible EPC capacities are shown. The “current” refers to the available capacity of the HVDC links with activated EPC today¹⁴. The “possible” takes the available capacity of all HVDC links into account. Neither of these capacity plots distinguishes what exact links have available capacity, and what the trigger levels of the EPC are.

¹⁴ Situation of May 2017.

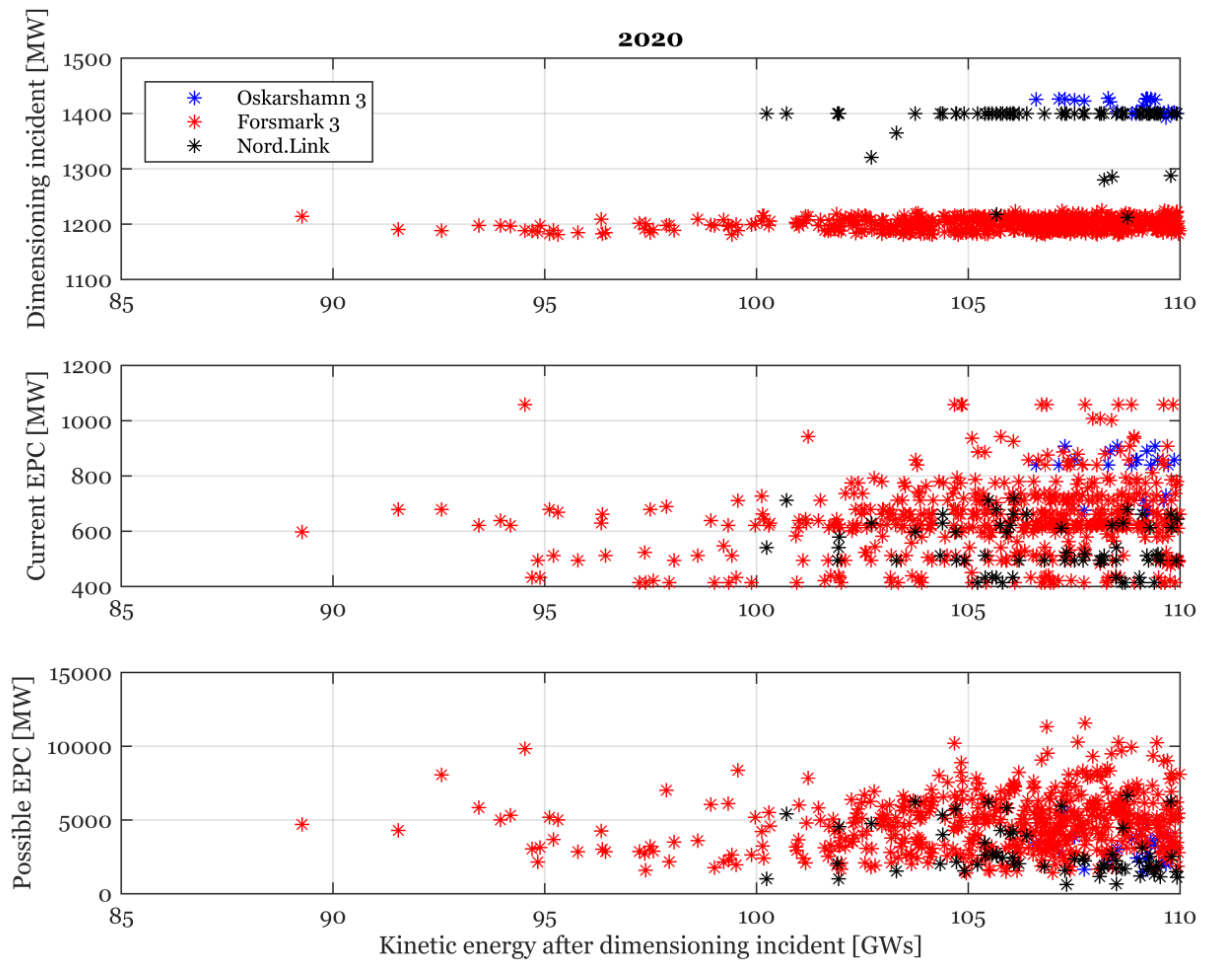


FIGURE 5-32 DIMENSIONING INCIDENT, CURRENT AND POSSIBLE EPC-CAPACITY WHEN KINETIC ENERGY AFTER FAULT < 110 GWs IN SCENARIO 2020; EACH ASTERISK INDICATES A DIFFERENT SYSTEM STATE. THE “CURRENT” REFERS TO THE AVAILABLE CAPACITY OF THE HVDC LINKS WITH ACTIVATED EPC TODAY . THE “POSSIBLE” TAKES THE AVAILABLE CAPACITY OF ALL HVDC LINKS INTO ACCOUNT.

During the low-inertia period for the 2020 scenario, it is common for Forsmark 3 to be the dimensioning incident. This results from both Olkiluoto 3 and Oskarshamn 3 being out for revision during the summer period. This situation is reflected by a very low kinetic energy and Forsmark 3 often being the dimensioning incident. During a number of periods, the HVDC Nord.Link will be the dimensioning incident.

The current EPC capacity is normally around 500 MW, while the possible capacity is often a lot higher.

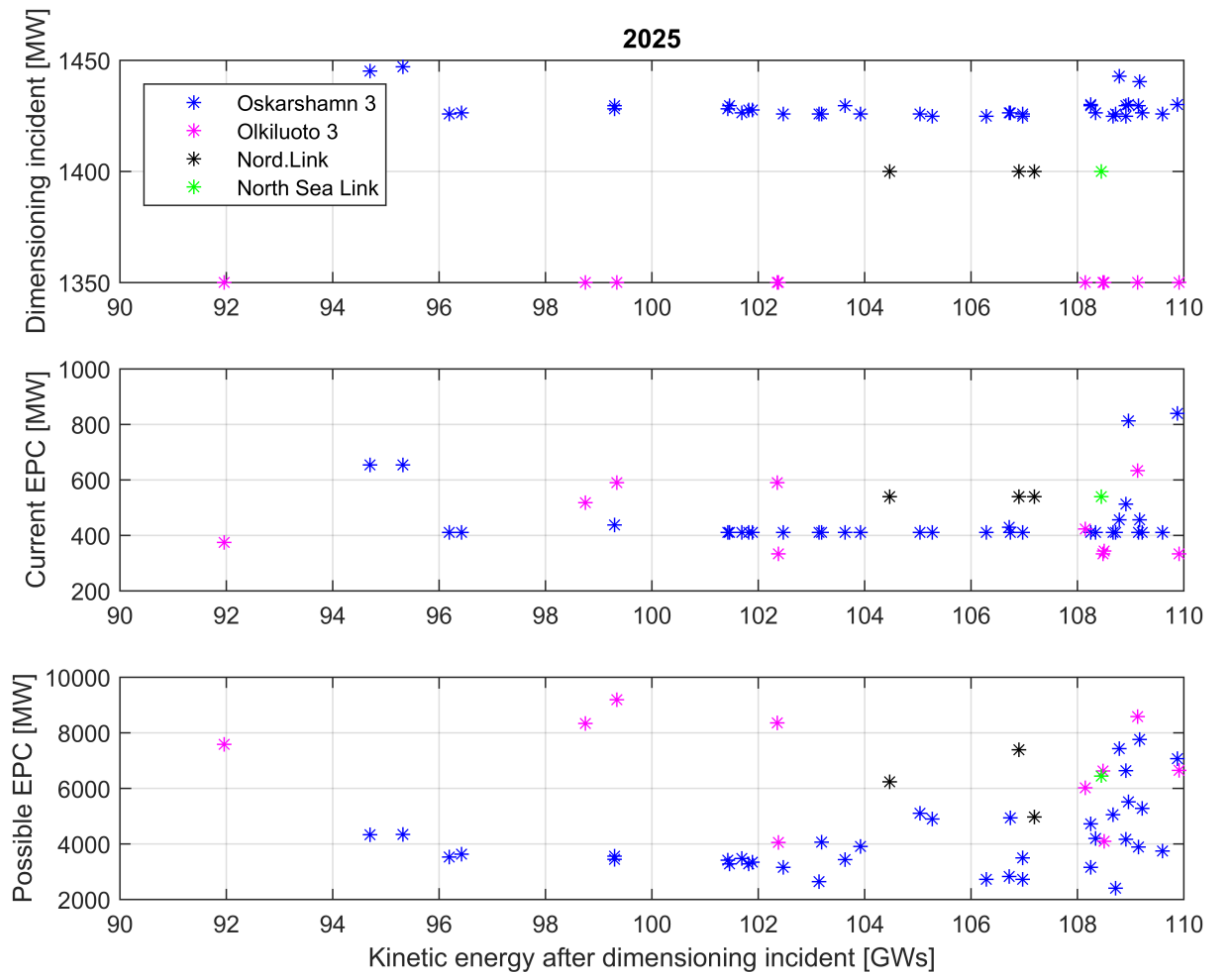


FIGURE 5-33 DIMENSIONING INCIDENT, CURRENT AND POSSIBLE EPC-CAPACITY WHEN KINETIC ENERGY AFTER FAULT < 110 GWs IN SCENARIO 2025; EACH ASTERISK INDICATES A DIFFERENT SYSTEM STATE. THE “CURRENT” REFERS TO THE AVAILABLE CAPACITY OF THE HVDC LINKS WITH ACTIVATED EPC TODAY . THE “POSSIBLE” TAKES THE AVAILABLE CAPACITY OF ALL HVDC LINKS INTO ACCOUNT.

In the 2025 scenario, there is not as many low kinetic energy periods as compared to 2020. Two major reasons for this is the increased load (Figure 5-30) and the higher availability of Olkiluoto 3 (Figure 5-31). As the inertia is higher, the dimensioning incidents are also higher compared to 2020. Instead of Forsmark 3, now the worst disturbances are Oskarshamn 3, Olkiluoto 3, or any of the HVDC links of 1 400 MW.

The EPC plot of the current capacity shows that the capacity is reduced from 500 MW (2020) to 400 MW (2025). It is important to make sure that the trigger levels and the capacity are distributed over the links, so that the system will get the needed emergency power. The possible capacity is over 2 000 MW for all periods which indicates that there should always be enough capacity available.

6. FAST-FREQUENCY RESERVES (FFR) AND SYNTHETIC INERTIA

In low-inertia situations the performance of the traditional hydropower-based FCR-D may not be sufficient to keep the frequency above 49 Hz in the event of a dimensioning incident. A straightforward solution could be to procure a larger volume of FCR-D, and thereby to increase the regulating strength. However, due to the inherent dynamics of the hydro power plants, stability issues may arise when the regulating strength increases (see also Section 3.2). One feasible solution to maintain secure operation is to introduce new products comprised under the category of synthetic inertia or fast-frequency reserves (FFR); FFR is a complimentary service with a response faster than FCR-D. Both products are elaborated upon in the sections below.

Examples of synchronous inertial response, synthetic inertial response, FCR-D hydro power response, and FFR (in the form of a proportional response and a temporary power boost) are compared to one another in Figure 6-1.

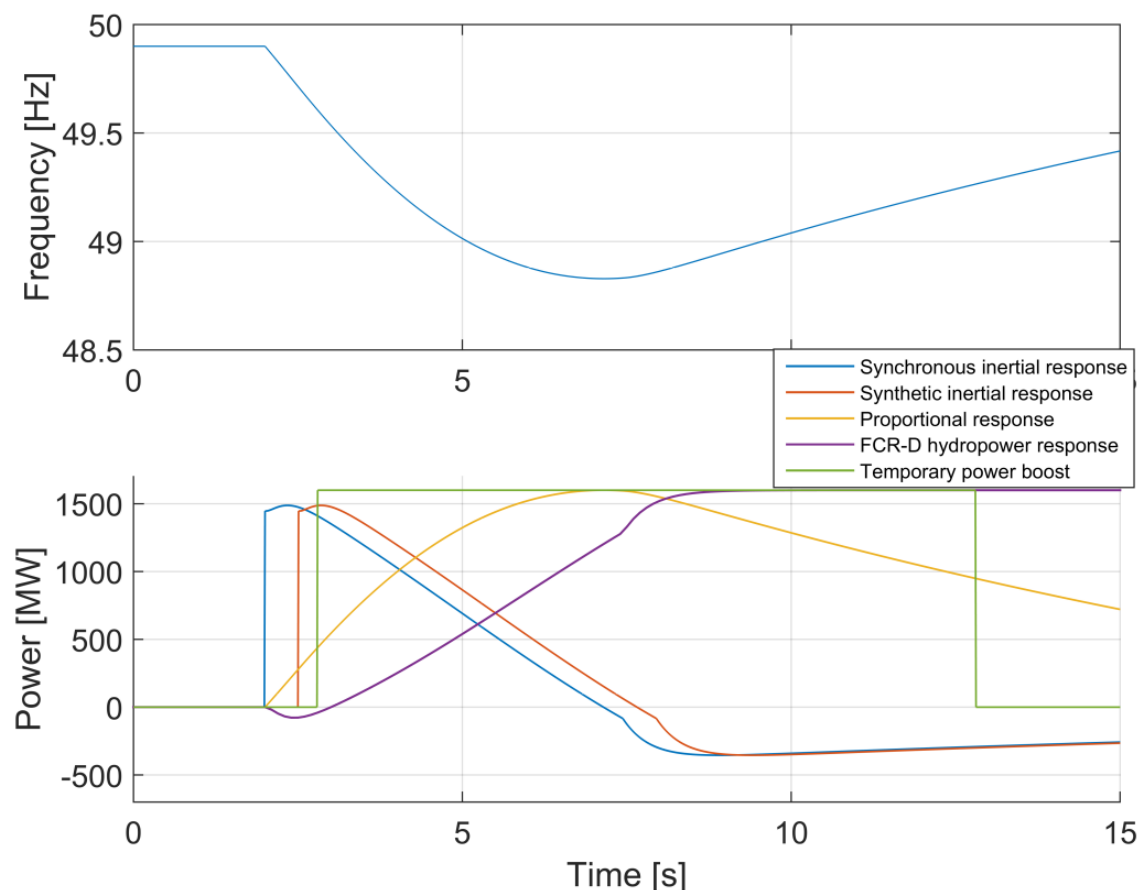


FIGURE 6-1 RESPONSES OF DIFFERENT PRODUCTS THAT ARE FACING THE MINIMUM FREQUENCY (OPEN-LOOP RESPONSE). NOTE THAT BOTH THE “PROPORTIONAL RESPONSE” (YELLOW CURVE) AND THE “TEMPORARY POWER BOOST” (GREEN CURVE) ARE FFR PRODUCTS

6.1 SYNTHETIC INERTIA

The inertial response of a synchronous generator releases torque in direct proportion to the RoCoF it experiences. The term synthetic inertia must therefore correspond to the controlled response from a generating unit to mimic the exchange of rotational energy from a synchronous machine with the power system. Any other form of energy exchange can then be labelled as being FFR.

The term inertia is described by ENTSO-E as *“The property of a rotating rigid body, such as the rotor of an alternator, such that it maintains its state of uniform rotational motion and angular momentum unless an external torque is applied”* [11]. The interpretation of this is that rotating masses of synchronous generators resist change of speed, unless there is a change in torque. The term synthetic inertia is described by ENTSO-E as *“the facility provided by a power park module or HVDC system to replace the effect of inertia of a synchronous power generating module to a prescribed level of performance”*. While this definition encompasses the definition presented in this report, many have interpreted this definition to include what we call FFR. In this report, synthetic inertia is defined as follows [12]:

Synthetic inertia is defined as the controlled contribution of electrical torque from a unit that is proportional to the rate of change of frequency measured at the terminals of the unit.

With reference to equation (3.5), the constant of synthetic inertia $H_{syn,i}$, for generator i is defined by the relationship between the terminal frequency ω_t , and $\Delta P_{e,i}$, being the additional electrical power provided by unit i [12]:

$$\Delta P_{e,i} = -2H_{syn,i} \frac{d\omega_t}{dt} \omega_t \quad (6.1)$$

The response of synthetic inertia – where the injected power is proportional to the frequency derivative ($\Delta P_{e,i} = -K_d \frac{df}{dt}$) – is simulated in a system with 100 GWs kinetic energy and a disturbance of 1 450 MW generation disconnection. In this illustration the synthetic inertia, equal to 20 GWs, is triggered if the frequency goes below 49.5 Hz, with an activation delay of 0.5 s. Figure 6-2 shows the frequency and the injected power from the synthetic inertia. Figure 6-3 shows the simulated RoCoF.

As measuring df/dt (RoCoF), is not a straightforward exercise, the practical application of synthetic inertia is still limited, as can also be observed from the survey responses in Chapter 4.

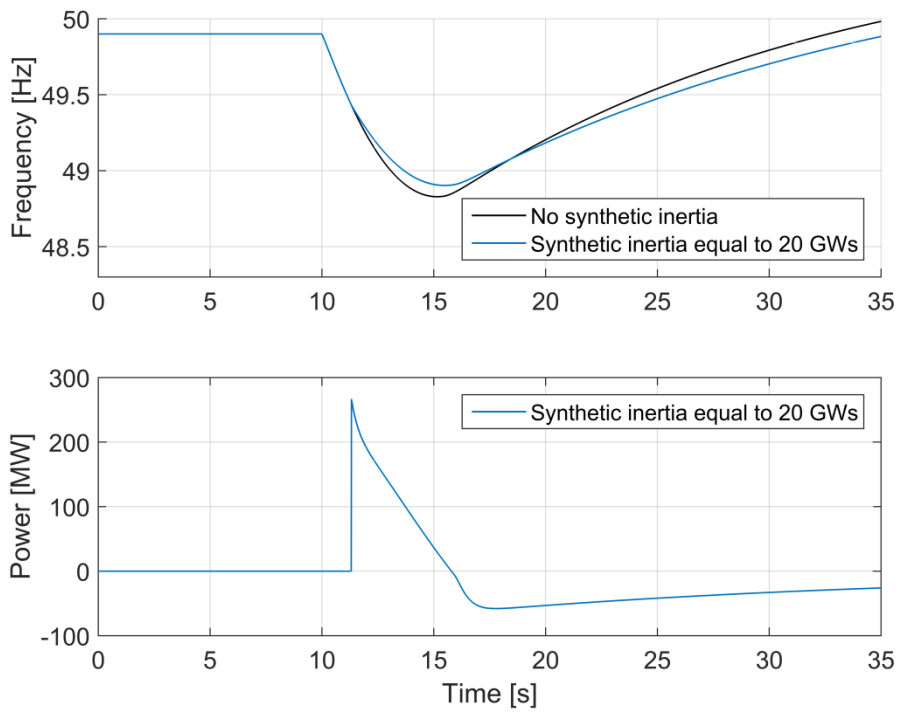


FIGURE 6-2 SIMULATED FREQUENCY AND INJECTED POWER USING SYNTHETIC INERTIA EQUAL TO 20 GWs

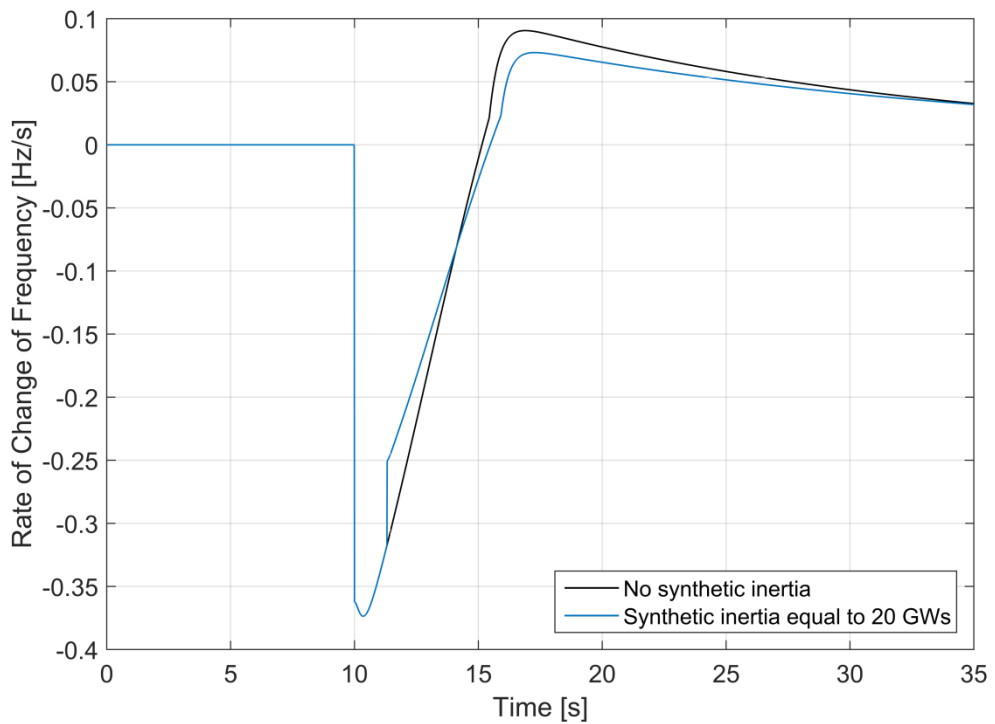


FIGURE 6-3 SIMULATED RoCoF USING SYNTHETIC INERTIA EQUAL TO 20 GWs

6.2 FAST-FREQUENCY RESERVES (FFR)

Fast-frequency reserves are defined in this reports as:

Fast-Frequency Reserve is a system service that delivers a fast power change to mitigate the effect of reduced inertial response, so that frequency stability can be maintained.

Though the requirements of an “FFR product” are not defined yet, what can be mentioned is that the FFR is a product that is faster than the FCR-D. Some possible characteristics of an “FFR product” are touched upon in the following sections.

6.2.1 FFR ACTIVATION

FFR products can be triggered to activate in different ways. In the event of a disturbance it may react on measurements. Some relevant measures, in this respect, are

1. Frequency deviation
(for example under-frequency $f < 49.9$ Hz; 49.75 Hz; 49.5 Hz, or over-frequency $f > 50.1$ Hz; 50.25 Hz; 50.5 Hz)
2. RoCoF
(for example under-frequency $df/dt \leq -0.035$ Hz/s, or over-frequency $df/dt \geq 0.035$ Hz/s)
3. Combination of options 1 and 2
4. Triggered by, for example, a relay signal or circuit breaker position.

The best time for activation depends on the type of source delivering the reserve. In the case of a provider that is not limited in energy supply (e.g. load disconnection), the largest impact on the frequency minimum is achieved by activating as fast as possible. In Figure 6-4, the effect of a 100 MW load disconnection is simulated for a system with 100 GWs. The disconnection occurs at $t = 10$ s. The y-axis explains how the minimum frequency of the disturbance will change due to the load disconnection. A positive number indicates that the minimum frequency occurs at a higher frequency when the load disconnection is included.

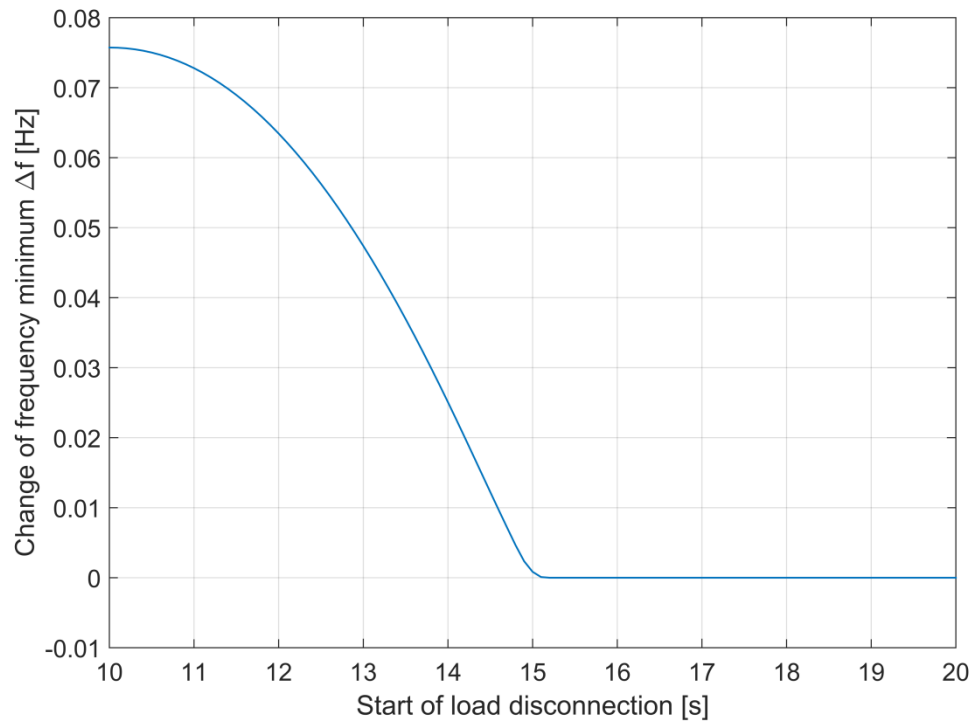


FIGURE 6-4 CHANGE OF FREQUENCY MINIMUM DEPENDING ON WHEN IN TIME 100 MW LOAD IS DISCONNECTED

If the reserve instead has a limitation in delivered energy (for example wind power, or a battery), it is not optimal to activate as fast as possible. In Figure 6-5, the impact of a 300 MW power pulse with a one-second duration is simulated. In the same way as for the load disconnection the y-axis describes how the minimum frequency will change due to the power pulse.

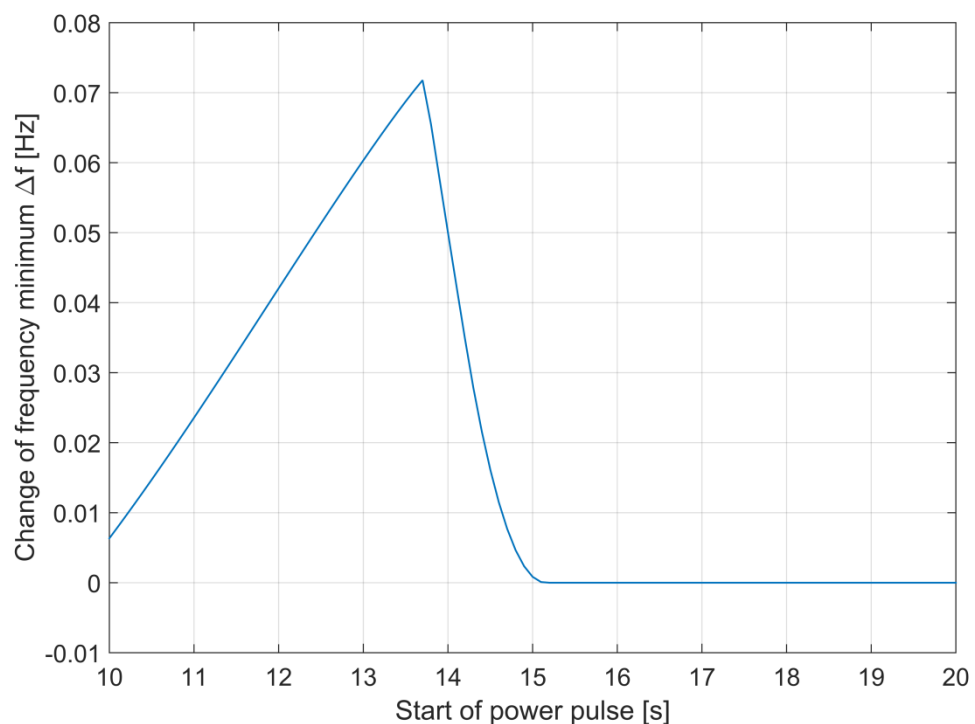


FIGURE 6-5 CHANGE OF FREQUENCY MINIMUM DEPENDING ON WHEN IN TIME A 300 MW PULSE WITH 1 S DURATION IS ACTIVATED

The simulation shows that it is better to wait with the activation, so that the energy is injected just before the frequency minimum. The reason is that the FCR reserves measure a greater frequency deviation, resulting in a faster FCR response, if the energy is injected just before the frequency minimum. If any of the parameters would change the optimal time would also change. In that sense the timings are only indicative.

6.2.2 FFR CONTROL

Once the FFR has been activated, it can be controlled to respond in many different ways. The control scheme can rely totally on feedback, and respond accordingly, or rely on feedforward. Feedforward here means that the FFR response is independent of the trajectory¹⁵ of the frequency. The idea behind feedforward is that the response of the system is predictable based on secondary measures. The likely response schemes are listed as follows:

1. Power proportional to the frequency deviation
($\Delta P_e = -K_p \Delta f$)
2. Predetermined power profile i.e. temporary power boost
(*for example a constant power step, like a trip of load or production*)

Response proportional to the frequency deviation, is the same as FCR, but it is a fast response in the case of FFR, such that it closely follows the reference. Responses from (many) relay-activated load disconnections, and power controlled by power electronics from batteries will be considered as FFR, for example.

The specific power profile can be determined by three periods, power rising, power constant, and power return.

To investigate the preferred control of FFR, both control proportional to the frequency and several predetermined power boosts are simulated separately, as shown in Figure 6-6. The frequency response is depicted in Figure 6-7; all reserves are activated at a frequency of 49.5 Hz, with a delay of 0.5 s, and have an energy limited to 400 MWs.

¹⁵ Frequency trajectory refers to the evolution of the frequency in the system after a disturbance, being affected by the response of the FCR.

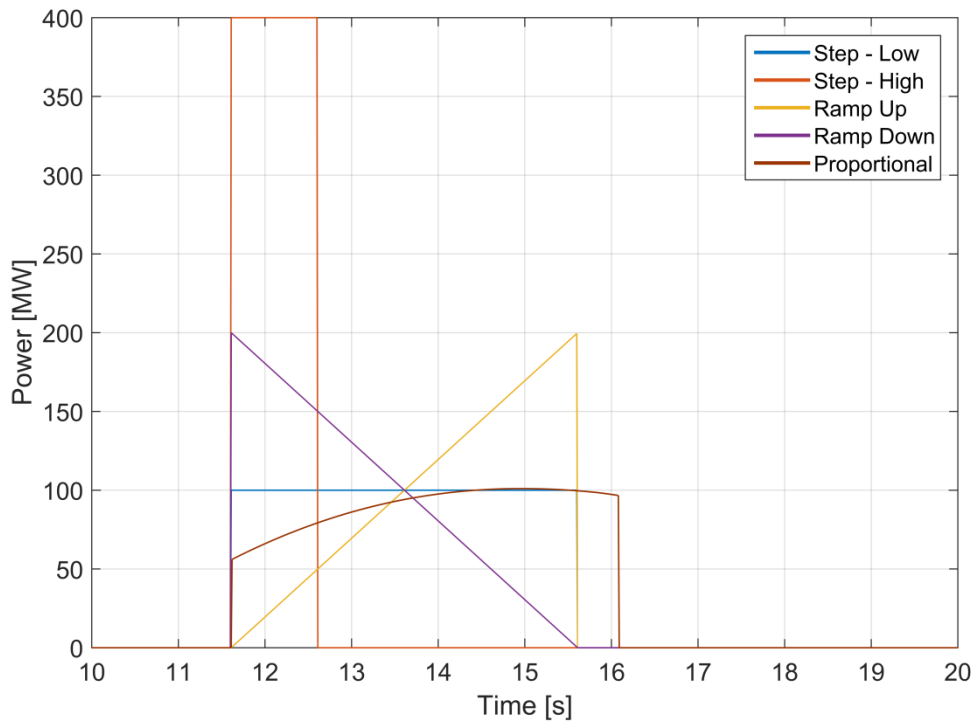


FIGURE 6-6 SIMULATED POWER OF PREDETERMINED POWER BOOSTS AND PROPORTIONAL CONTROL

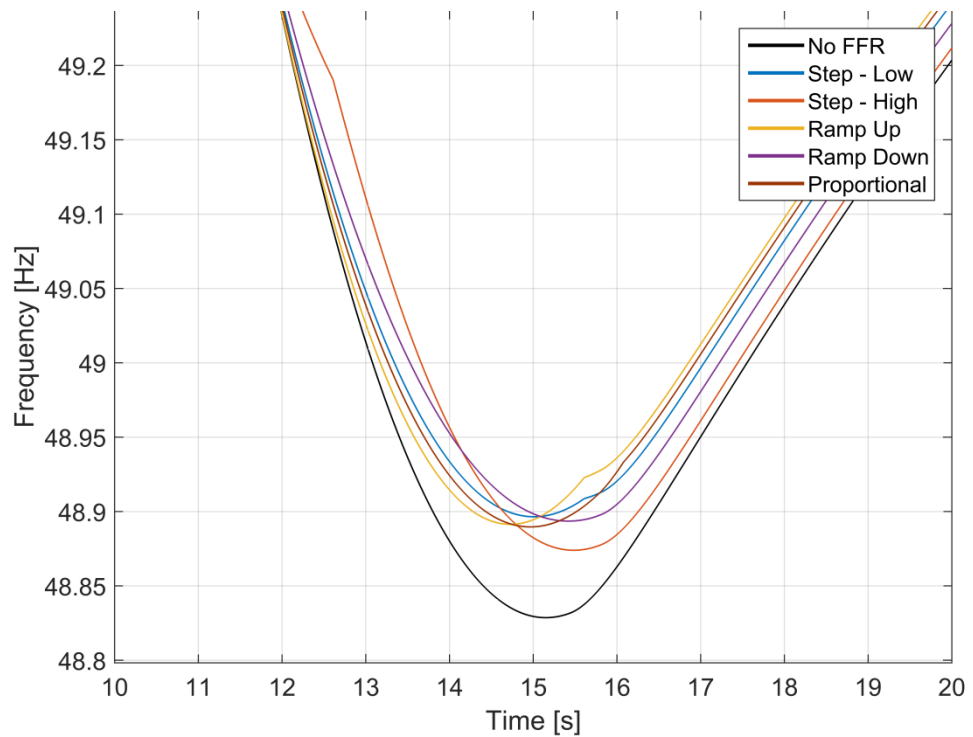


FIGURE 6-7 SIMULATED FREQUENCY OF PREDETERMINED POWER BOOSTS AND PROPORTIONAL CONTROL

The results of the simulation confirm the simulations in Section 6.2.1, the injected power has more impact closer to the frequency minimum. The red curve, representing a high magnitude with short

duration, activates too early to inject power close to the frequency minimum. The other alternatives have longer durations resulting in power injection at the time of the frequency minimum. The best alternative for this specific simulation is the step with the low amplitude, but the difference is very small compared to the proportional and ramps. The proportional controller can tune the gain to have a more or less aggressive response. In this case it is tuned to be able to deliver power during the frequency minimum. The benefit of using a proportional controller is that the strongest response will be achieved at the frequency minimum, which is the most beneficial, as long as there is energy available.

One danger with using a predetermined power boost without feedback of the frequency, is that a fast response with limited energy will make the primary reserve see a smaller frequency deviation. When the power boost is over, the frequency will fall and a second lower frequency minimum may occur. Using a proportional control, with less aggressive tuning, will minimise the power injection when the energy limit is reached. In Figure 6-8 and Figure 6-9 the responses of a predetermined step and a proportional control are simulated. In this case the energy is limited to 10 000 MWs.

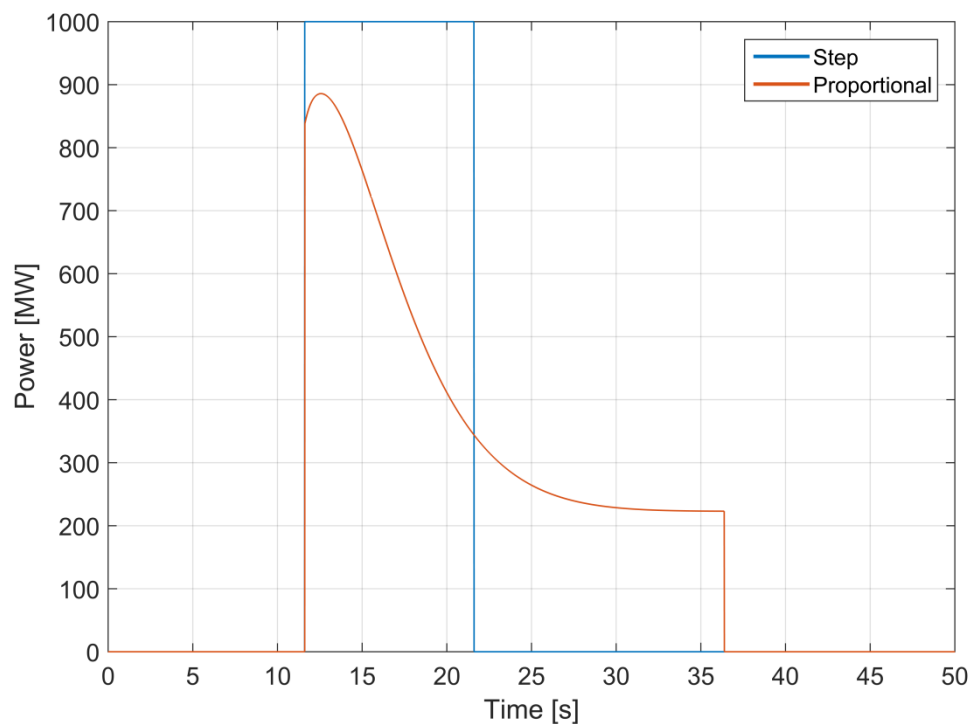


FIGURE 6-8 RESPONSE OF A PREDETERMINED STEP (POWER BOOST), AND PROPORTIONAL CONTROL WITH HIGH CAPACITY

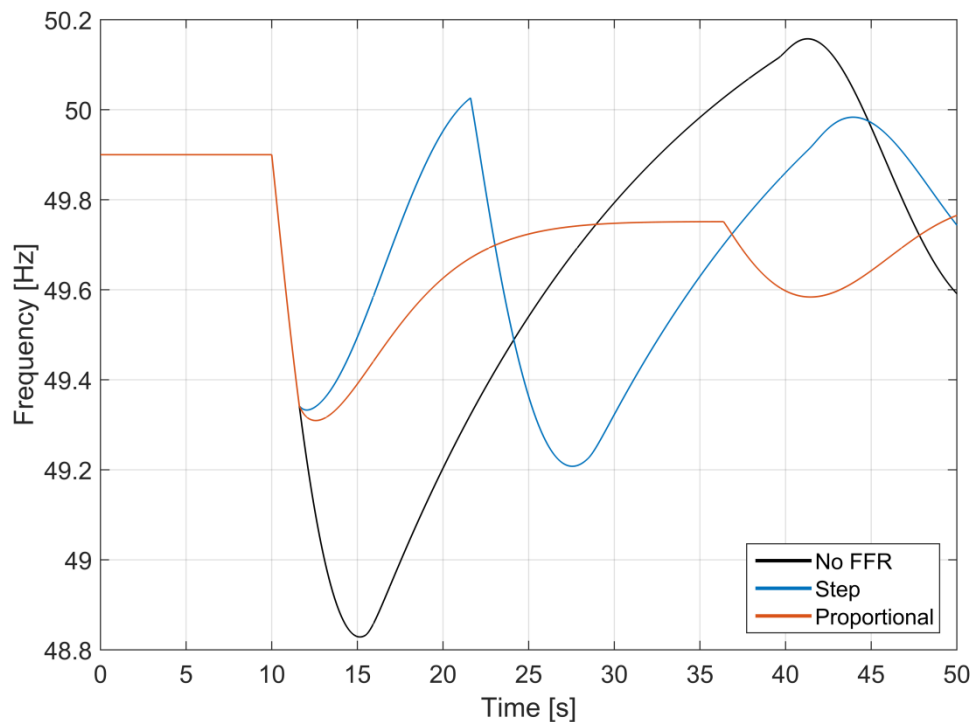


FIGURE 6-9 FREQUENCY FOR A PREDETERMINED STEP POWER BOOST AND PROPORTIONAL CONTROL WITH HIGH CAPACITY

The first frequency minimum is higher for the power boost, but then too much energy is injected to the system and the FCR-D response is cancelled. When the power boost ends, it is similar to a trip of 1 000 MW, resulting in a second frequency minimum at 49.2 Hz. For the proportional controller the support is highest during the frequency minimum and then the support is reduced, shifting the burden over to the FCR-D. When the energy limit is reached, approximately 200 MW disconnects, compared to 1 000 MW in case of the power boost. This also results in a second frequency minimum, but with higher frequency compared to the power boost.

6.2.3 FFR DURATION

The possible duration of the FFR highly depends on the technology providing the service. However, studying the durations from a control perspective it can remain active

1. For a fixed amount of time (for example 10–20 seconds)
2. Until the RoCoF returns within certain limits
(for under-frequency $df/dt \geq X$ Hz/s, and for over-frequency $df/dt \leq X$ Hz/s, e.g. $X = 0$)
3. Until the frequency returns within certain limits
(for under-frequency $f \geq Y$ Hz, e.g. $Y = 49.9$ Hz)
4. Combination of options 1–3

The duration time of the reserve is very important as seen in Section 6.2. The injected power must have a duration long enough to not create a lower second minimum frequency, as seen in Figure 6-9. The shortest duration needed is related both to the shape and volume of the reserve as well as to the system kinetic energy. Simulations of the shortest duration needed, in order to prevent a

lower second frequency minimum, are performed using a step-shape power injection. In Figure 6-10, the reserve is activated directly at the time of the disturbance and in Figure 6-11 at 49.5 Hz. The y-axis “Shortest duration of fast reserve”, presents the duration needed in order for the second minimum frequency to not have a lower frequency compared to the first minimum frequency of the disturbance. The x-axis indicates the volume of the injected power step.

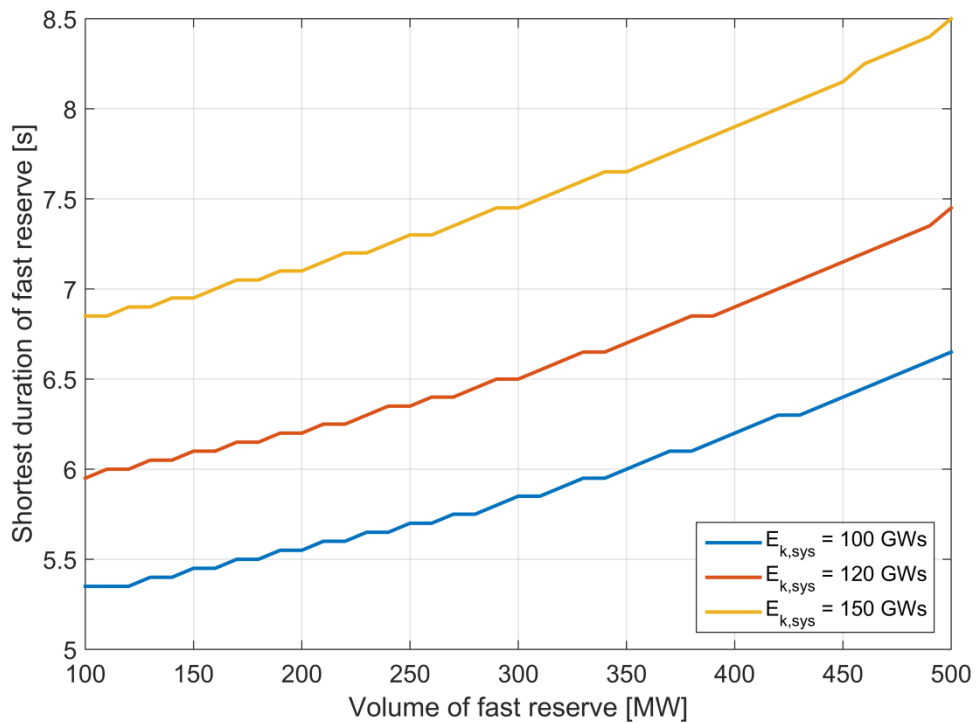


FIGURE 6-10 SIMULATION OF SHORTEST DURATION NEEDED – ACTIVATION AT START OF DISTURBANCE

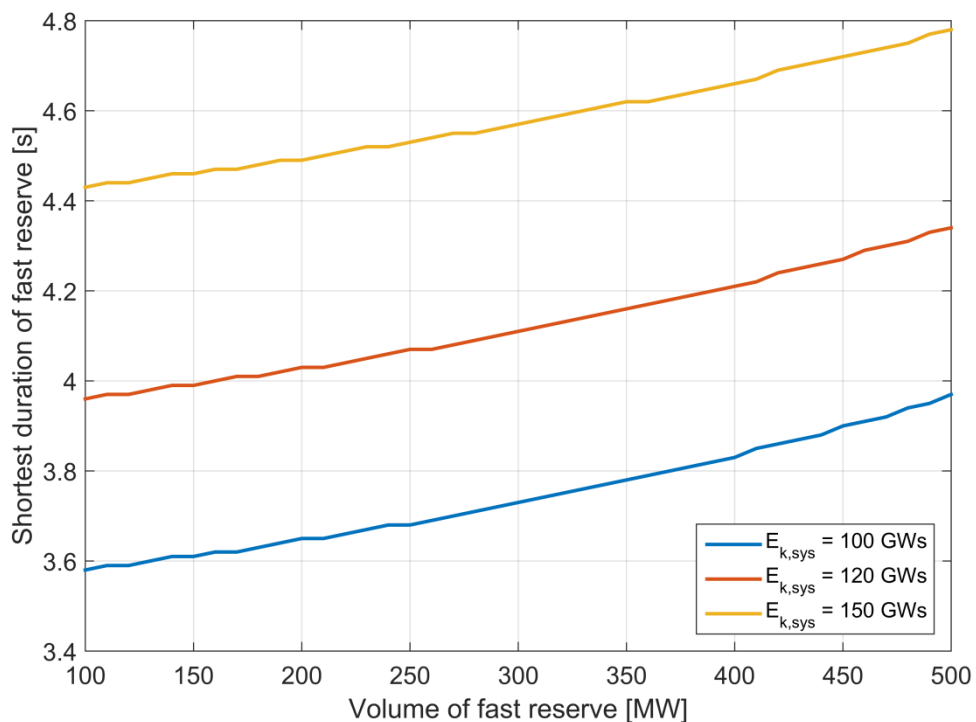


FIGURE 6-11 SIMULATION OF SHORTEST DURATION NEEDED – ACTIVATION AT 49.5 HZ

From the simulations it is possible to see that the duration for a 100 GWs system must at least be 6.6 s, when the 500 MW reserve is activated directly after the disturbance. For increased kinetic energy in the system the time increases, but the minimum frequency will not be as low as in a low-inertia system.

6.2.4 FFR ACTIVATION TIME (DELAY) OPTIONS

Activation time or delay for activation includes the time needed for example for filtering of frequency and RoCoF measurements, as well as time needed for control loops. Options for the activation time are

1. Fixed amount of time
(for example 1 s; time stamps of signals would be needed)
2. As soon as possible (i.e. as soon as the information has been processed)

6.2.5 FFR OVERVIEW

Table 6-1 provides an overview of the technologies that may provide FFR, as well as some of their properties in this respect.

TABLE 6-1 TECHNOLOGIES TO PROVIDE FFR, AND THEIR PROPERTIES

CONTROL: A: $K df/dt$ (SYNTHETIC INERTIA), B: $K\Delta f$, C: PREDETERMINED POWER PROFILE, D: SYNCHRONOUS INERTIAL RESPONSE

| Technology Property | Relay-connected load | Converter-connected load | Wind power | Battery | HVDC EPC | Flywheel converter connected | Synchronous condenser |
|--|----------------------------|----------------------------|---------------------------------------|------------------------|------------------------|------------------------------|-----------------------|
| Activation time | instant | <0.5 s | <0.5 s | <0.5 s | <0.5 s | <0.5 s | instant |
| Duration | minutes | minutes | 10 % for about 10 seconds | minutes | N/A | seconds | seconds |
| Control | C | B, C | (A) ,B, C | A, B, C | A, B, C | A, C | D |
| Frequency Up regulation Down regulation | Pload N/A ¹⁶ | Pload N/A ¹⁶ | 10 % Up to the actual power output | Pmax-Pset Pmin-Pset | Pmax-Pset Pmin-Pset | Rated power N/A | N/A |

¹⁶ In theory, some loads can be increased to provide frequency down-regulation. This is the case for thermal loads, like cooling houses, for example.

7. EMERGENCY POWER CONTROL (EPC)

One way of mitigating too low frequency excursions in the Nordic synchronous area in low-inertia situations, is by changing the settings of the Emergency Power Control (EPC) activation on the HVDC links. This is elaborated upon in the following sections.

7.1 CURRENT EPC SETTINGS

Today there is no common philosophy of how the EPC settings are chosen. Today's EPC settings are tabulated in Table 3-4. Each EPC is designed with not much consideration to the other EPCs; some EPCs change the ramp rate when the next step is activated (Kontiskan 2), and some increase the capacity instead (SwePol).

Simulations, using the model described in Section 3.3, show that many of the links use settings that result in a very slow response that hardly affects the minimum frequency, after a disturbance occurs. The current settings cause most of the EPC's power to be provided after the frequency minimum occurred. The simulations are performed for a dimensioning incident of 1 450 MW, using the estimated FCR response model in Section 3.3, and a system kinetic energy of 100 GWs. Each EPC response is simulated separately, to investigate how the minimum frequency is affected. When the frequency decreases, more steps are activated. In the simulation it is assumed that there is always capacity available for the EPCs. Figure 7-1 shows the simulation of the EPC response from Kontiskan 2. The blue curve represents the case where the EPC is unavailable. The yellow, red, and purple lines represent the cases where the different EPC steps are activated.

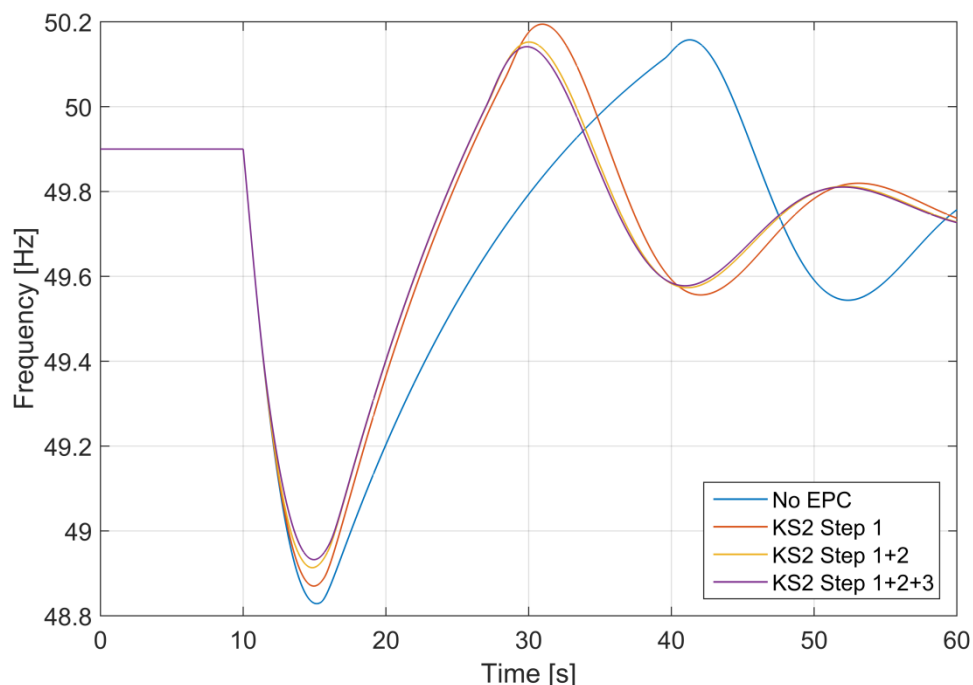


FIGURE 7-1 SIMULATION OF EMERGENCY POWER CONTROL ACTIVATION FROM KONTISKAN 2

For Kontiskan 2, the capacity is the same for all the steps but the ramp rate increases for each activated step, as shown by the active power plots in Figure 7-2. This is the reason why the case, where all the steps are activated, has more effect on the minimum frequency compared to the first step only.

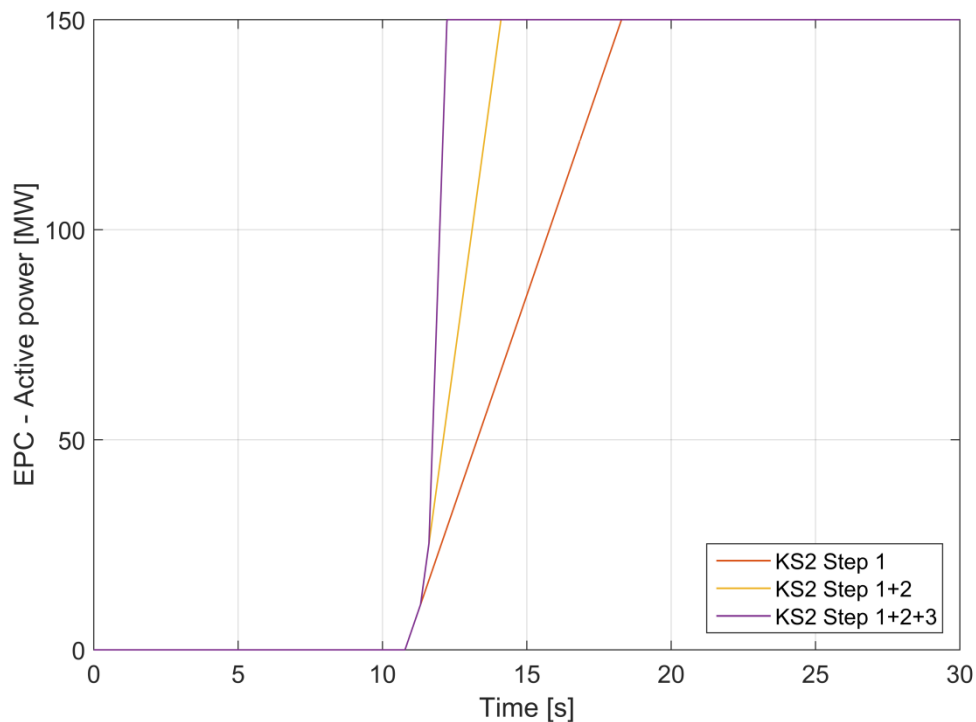


FIGURE 7-2 INJECTED POWER FROM KONTISKAN 2 EPC

A comparison on how much the minimum frequency is raised for each EPC, based on its capacity, is shown in Table 7-1. The simulated disturbance is so severe, that all steps will be activated when the EPCs are simulated separately. The ramp rate of the last step, for those EPCs that alter the ramp rate when the next step is activated, is therefore considered in Table 7-1. When the capacity of the EPC changes in steps, the impact of those capacity changes are simulated and tabulated separately.

TABLE 7-1 SIMULATED PERFORMANCE OF EPCS AFTER A 1 450 MW DISTURBANCE IN A 100 GWS SYSTEM

| HVDC link | Used capacity [MW] | Increase of minimum frequency Δf [Hz] |
|---------------|--------------------|---|
| Kontiskan 2 | 150 | 0.104 |
| Baltic Cable | 150 | 0.089 |
| | 300 | 0.122 |
| SwePol link | 150 | 0.078 |
| | 300 | 0.095 |
| Great Belt | 18 | 0.010 |
| Skagerrak 1&2 | 120 | 0.039 |
| Skagerrak 3 | 120 | 0.028 |
| Kontek | 50 | 0.014 |
| NordBalt | 150 | 0.094 |
| | 300 | 0.145 |

The performance of the EPCs varies a lot depending on the settings. All links using a ramp rate below 100 MW/s don't have a large impact on the frequency minimum. Another reason for the poor performance is that the EPCs activate at a too low frequency to make any difference. Slow response, and activation at a too low frequency, make the EPCs use more capacity of the HVDC link than necessary to affect the lowest frequency. Indeed, the power is then injected into the system when the frequency minimum already has occurred. Even though a high ramp rate is used for Baltic Cable and SwePol link, the second step - activating an additional 150 MW - has a low impact compared to the first step of 150 MW. The reason is the low activation frequency, especially for SwePol link. NordBalt is an example where low activation frequencies still result in a good impact on the frequency. The reason is the very high ramp rate of 990 MW/s¹⁷. If the EPCs are to be considered as low-frequency mitigation measures, the available capacity must be observed by the control centre in real time in order to not overestimate it.

7.2 REDESIGN OF EPC SETTINGS

A redesign of the EPC settings, on a common basis, has a great potential to mitigate too low frequency excursions in the Nordic synchronous area in low-inertia situations. Some suggestions to alter the EPC settings are listed below:

- Use a high ramp rate (at least 100 MW/s). A high ramp rate is needed to inject the power before the frequency minimum is reached.
- Distribute the frequency triggers evenly among the different DC links, within a range of approximately 49.7–49.3 Hz. In that way the EPC will only activate when a severe disturbance occurs, and at the same time be able to affect the frequency minimum.
- There is no need to use too much volume per link (100 MW per link is fine). The important thing is to get the power in before the frequency minimum. There is no added value to feed in a lot of power after the frequency minimum.

Three EPCs, using the settings specified in Table 7-2, are simulated together in order to analyse the impact on the frequency. The responses are shown in Figure 7-3 and Figure 7-4.

TABLE 7-2 NEW EPC SETTINGS

| EPC | Frequency trigger [Hz] | Capacity [MW] | Ramp rate [MW/s] | Time delay [s] |
|-----|------------------------|---------------|------------------|----------------|
| 1 | 49.6 | 100 | 100 | 0.5 |
| 2 | 49.5 | 100 | 100 | 0.5 |
| 3 | 49.4 | 100 | 100 | 0.5 |

¹⁷ If this high ramp rate would be used in practice, studies should be done to ensure there are no system or grid issues.

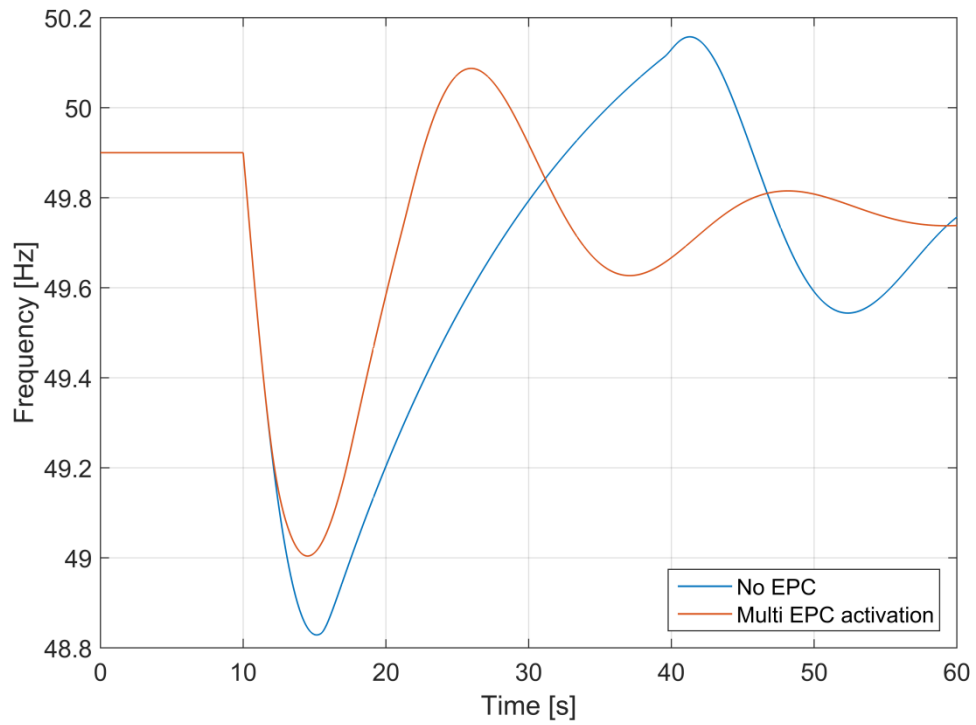


FIGURE 7-3 SIMULATION OF THREE EPCs USING SETTINGS FOR FAST RESPONSE

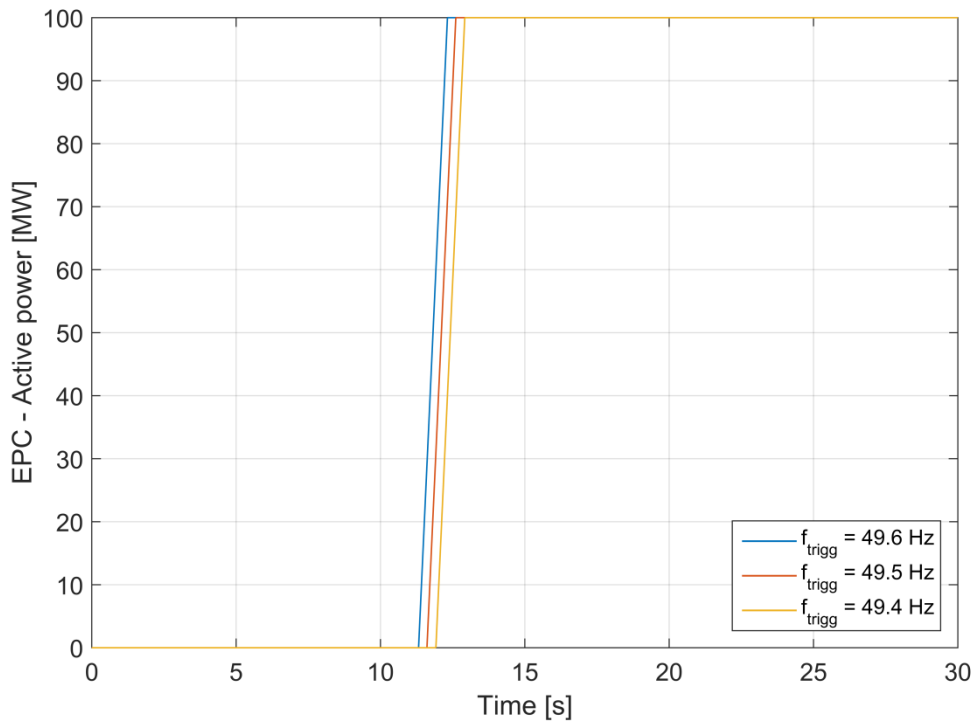


FIGURE 7-4 INJECTED POWER FROM THE THREE SIMULATED EPCs

The frequency minimum is increased by 0.175 Hz by only utilizing 300 MW EPC power in total. When we compare this number with the ones in Table 7-1 (based on the current EPC settings), it

shows a very good performance indeed. Except for NordBalt, that is using an extreme ramp rate of 990 MW/s, the new settings in Table 7-2 provide superior performance for the same capacity. Dividing the EPC capacity to several links also increases the chances that the capacity required is actually available at the time of a disturbance.

8. MITIGATION MEASURES TO HANDLE LOW KINETIC ENERGY

SITUATIONS

In order to prevent load shedding (on the under-frequency side), or generation shedding (at the over-frequency side), the frequency in the Nordic synchronous area needs to remain within a frequency band of 49–51 Hz after the occurrence of an N-1 disturbance. The ‘dials’ to reach this objective are schematically depicted in Figure 8-1.

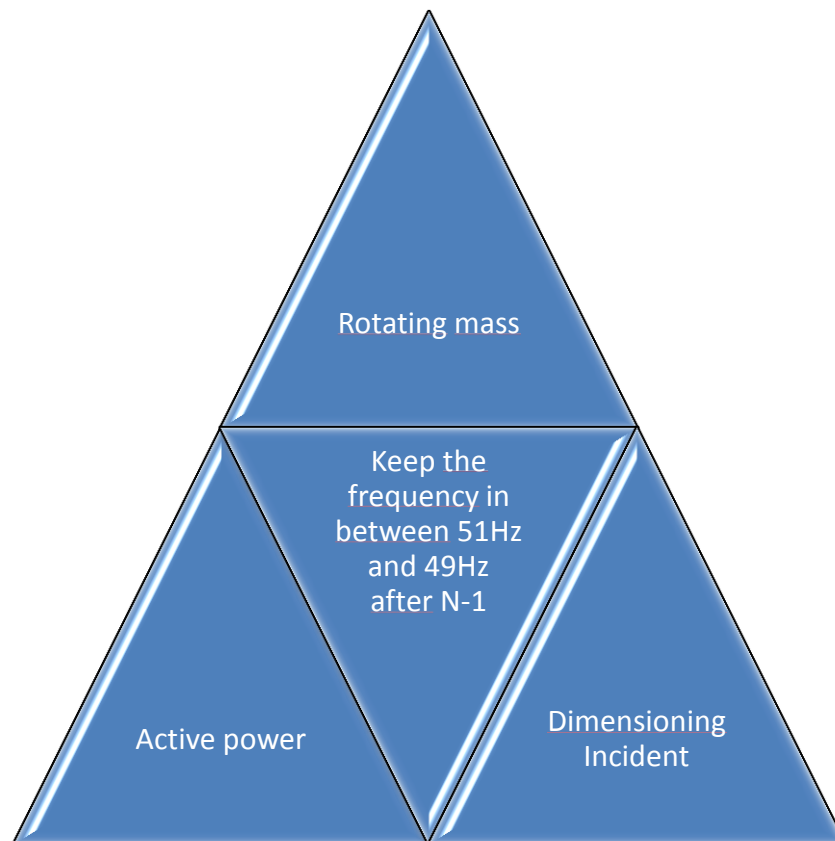


FIGURE 8-1 ‘DIALS’ TO KEEP $49 < f < 51$ HZ AFTER N-1

The rotating mass in the system consists of:

- Synchronous machines
- Synchronous condensers

The Dimensioning Incident (DI) is the largest production or consumption unit in the system at a specific moment in time, that can be subject to an outage (the N-1). By reducing the amount of active power being produced or consumed, the impact (frequency excursion) of this so-called DI can be limited. The following grid components may be impacted by this reduction of the DI:

- Thermal (nuclear) power plant
- HVDC connection

Instead of active power being extracted from the rotating mass in the system, active power can also be injected when needed to limit the frequency excursions, and to support the frequency restoration. On a high level, the following sources of power qualify to do so:

- Synchronous machines
- All sources of power behind power-electronic converters
- Load reduction

Indeed, the focus is on technical mitigation measures. As such, the two following actions are mentioned, yet not elaborated upon nor studied in this report:

- Operate the power system at a higher frequency (0.1 Hz) during low-inertia situations; this action may serve as a measure of last resort
- Coordinate the outage planning of the nuclear power plants and the HVDC links, so that not all revisions materialize in July or August.

The different mitigation measures are elaborated upon in the following sections. Costs are quantified where quantification is possible, and otherwise discussed qualitatively, separating between

- Implementation costs. The implementation costs cover the necessary preparation for capability, including control, configuration, and prequalification.
- Ex-ante costs. Ex-ante costs are related to the actions that need to be taken just to prepare that an N-1 fault can happen during minimum-inertia situations. For example starting up more rotating mass, decreasing the N-1, or reserving FFR capacity are considered to be ex-ante costs. Or in other words: the cost made, to reserve a measure beforehand in order to deal with low-inertia situations.
- Ex-post costs. Ex-post costs materialize in case an N-1 fault does occur during a low-inertia situation. So, for example, the costs related to the activation of FFR, load shedding, or extra FCR-D; please note that the reservation of the capacity of these measures are considered to be ex-ante costs. As the probability of an N-1 (or smaller failure) during low-inertia situations is quite low, the ex-post costs are most likely quite low as well.

The socioeconomic costs are our main interest. These are strongly related to the costs of provision when fuel usage is involved, and more loosely related when capacity is kept from the energy market. A more extensive and fundamental reflection on the costs of ancillary services is provided in Appendix C.

The impact of the different mitigation measures has been assessed as well. In order to make the numbers comparable, a reference situation has been assumed, and the volume of the mitigation measure needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system, is assessed. The simulations are performed for a dimensioning incident of 1 450 MW, using the estimated FCR response model in Section 3.3, where the frequency before the disturbance is at 49.9 Hz.

8.1 ROTATING MASS

When a low-inertia situation occurs, one of the potential mitigation measures is to bring in more rotating mass / inertia into the system. Some of the options to realize this, are discussed in the sections below.

8.1.1 SYNCHRONOUS CONDENSERS

A synchronous condenser is equivalent to a synchronous generator where the shaft is not connected to a turbine. Besides the application of synchronous condensers for reactive power support in the system, they provide inertia to the system as well. Some synchronous generators provide the possibility to disconnect the turbine shaft, so that they can be operated as a synchronous condenser, or may provide this possibility after some adjustments to the existing unit.

In the tabular overviews below, the currently-existing synchronous condensers in the Nordic system are listed (Table 8-1), as well as the possibilities for the Nordic TSOs to operate synchronous generators as synchronous condensers (potentially after some adjustment of the units) (Table 8-2).

TABLE 8-1 EXISTING SYNCHRONOUS CONDENSERS IN THE NORDIC SYSTEM

| Existing synchronous condensers in the Nordic system | Energinet | Fingrid | Svenska kraftnät | Statnett |
|--|--|---------|------------------------------|---|
| | Denmark | Finland | Sweden | Norway |
| Rated power, inertia constant | 2 units: 270 MVA, 1.68 s 200 MVA, 2.27 s | 0 unit | 1 unit: 140 MVA, 1.6 s | 7 units: 865 MVA, 1.7–3 s (avg. 2.1 s) |
| Total kinetic energy | 0.91 GWs | 0 GWs | 0.22 GWs | 1.71 GWs |

TABLE 8-2 SYNCHRONOUS GENERATORS THAT CAN BE OPERATED AS SYNCHRONOUS CONDENSERS

| Synchronous generators that can be operated as synchronous condensers (potentially after adjustments) | Energinet | Fingrid | Svenska kraftnät | Statnett |
|---|-----------|--------------|--|---|
| | Denmark | Finland | Sweden | Norway |
| Number of qualifying units | 0 | 15 | 19–20 / 3 | 6 (and 9 which are normally not in operation) |
| Type of generators | | Gas turbines | Gas turbines / Hydro turbines | Gas turbines |
| Ownership of the unit (TSO, market) | | 15 – TSO | 11 – TSO 9 – market / 3 – market | market |
| Adjustments needed before synchronous condenser mode is | | Yes | No / maybe for some | Yes |

| | | | | |
|---|-------|-----------|---|-------------------|
| available? | | | units. | |
| Approximate cost to adjust the units to run in synchronous condenser mode | | 300 k€ | | |
| Rated power, inertia constant | | 20-50 MVA | 40–87.5 MVA, 1–2 s / 160 MVA, 3 s | 50 MVA, 1.02 s |
| Total kinetic energy | 0 GWs | 0.35 GWs | 1.5–4 GWs | 0.31 GWs |

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Some modifications are needed to adjust gas turbines to operate as synchronous condensers in Finland and Norway. These costs are considered to be moderate.
- Ex-ante costs. This covers the energy costs, related to the losses, of running the unit as a synchronous condenser. Other units may be needed to replace the gas turbines that are used as synchronous compensators, as these are normally reserved for the mFRR capacity.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

The costs for the use of synchronous compensators, and running generators as synchronous compensators, are moderate. However, the volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system is 20 GWs, so it is obvious that the use of the existing synchronous condensers (2.8 GWs), and the synchronous generators operated as condensers (max. 4.7 GWs), is not a sufficient measure for low-inertia situations.

8.1.2 CONDENSER SERVICE OPERATION OF PELTON TURBINES

Hydropower units can be used as synchronous condensers, making them spin without discharging water; the generator operates as a motor and withdraws active power from the grid. Since the combined weight of the generator and turbine is much bigger than for an ordinary synchronous condenser, a hydro unit delivers approximately 50 % more rotational energy. Pelton turbines rotate in air and require minor adjustments to operate as synchronous condensers.

This section is based on a study delivered by Norconsult [13].

Potential

In the Nordic power system, there is about 45 000 MW of hydropower in units >10 MW installed. Among these, Pelton turbines represent about 7 700 MW, all in Norway. After 2020, the expectation is that Francis turbines will replace some of the Pelton turbines.

The Norconsult study assumes that all Pelton turbine capacity can operate as synchronous condensers at moderate but varying implementation cost, depending on the access to cooling water:

- Units that discharges into a lake or river will have easy access to cooling water. Approximately 3 500 MW belongs to this group of turbines. Note that the need for cooling can vary. North California Power Agency has several years of experience with Pelton turbines running as synchronous condensers without cooling of the turbine and without heating problems. The stations in California are mainly outdoors, while most Norwegian units are inside the mountains. The location of the unit is probably decisive for its ability to remove heat, and the assumption is that 2 % of nominal water flow is necessary in the Norwegian units for cooling.
- The remaining units (4 200 MW) need to use high-cost water from the penstock, or invest in a heat exchanger system and modify generator cooling to a closed-loop system for permanent condenser service operation.
 - A portion of the 4 200 MW has already high-pressure cooling water supply provisions from the penstock. The total capacity of such units is around 1 800 MW.
 - For plants that are not equipped with a penstock fed cooling system, an investment associated to this arrangement would be necessary. For a typical 100 MW plant, this investment would be in the range of 0.22–0.33 M€, including tapping off the penstock, energy dissipation, and piping.

The total potential, if all Pelton turbines operate as synchronous condensers, with the assumption of $\cos(\varphi) = 0.9$, and $H = 3$ s, amounts to 25 GWs. Around 5 500 MW of the Pelton turbines (those with water discharge in lakes and rivers, and those having cooling water supply from the penstock) can be used as synchronous condensers on relatively short notice. The potential inertia contribution from these units amounts to approximately 18 GWs.

Activation

Units that do not contribute in the energy spot market during the summer period, could be available for synchronous condenser operation in low-inertia situations.

Cooling costs

Cooling of the turbine chamber requires 2 % nominal water flow. As an example, for a 100 MW generator with cooling fed from the penstock, and a water value of 45 €/MWh, the hourly cooling cost is equal to the energy cost of 2 MWh, i.e. 90 €. With a $\cos(\varphi) = 0.9$, and $H = 3$ s, the inertia provided is 0.33 GWs, and the unit cost is equal to 270 €/GWs/h.

Note that in hours of low spot prices, with say a fifth of the water value, the energy cost of the 2 % nominal flow for cooling could reach and exceed 10 % of the cost of 100 MWh in the spot market. At extremely low spot prices, it could be more efficient to deliver energy from the Pelton unit at minimum load, given some incentive to provide inertia.

Note that the cost described above is proportional to the water value and applicable when the turbine is cooled with primary water from the penstock. Cooling water pumped from the tailrace, possible for 3 500 MW of the installed Pelton capacity, will be less expensive, for two reasons:

- The energy use will be lower, as the pumping head is much lower than that of the water reservoir, relative to the turbine.
- The energy cost will be a function of the energy spot price, and not of the (higher) water value.

For the generators that also need extra cooling of the generator, the Norconsult study assumes an additional 25 % of water. The total unit cost of inertia in the example increases to 337 €/GWs/h if cooling is done with primary water.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Cooling equipment (at a moderate but unknown cost), potential implementation of a suitably-sized penstock fed system (0.22–0.33 M€)
- Ex-ante costs. This covers the energy costs, related to the cooling, of running the unit as a synchronous condenser: 270–337 €/GWs/h at a water value of 45 EUR/MWh if primary water is used. Lower costs if cooling is done with pumping of discharge water.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 20 GWs. As such, the estimated inertia of max. 25 GWs from Pelton units represent a considerable potential for mitigation of low-inertia situations. The most cost-efficient units are those having access to cooling water from the tailrace, representing a little less than half the total potential.

8.1.3 INERTIA FROM THE GAS TURBINES

Fingrid and Svenska kraftnät have some gas turbines for fast-disturbance reserve. Gas turbines can be used as a “real” inertia by running them at minimum power. For example, Fingrid owns 24 gas turbine units, that have a total apparent power of 1 034 MVA. Fingrid also rents some gas turbines; the data of these 5 units – with a total apparent power of 199 MVA – have been used here for the calculations. The minimum power output for a safe use of the gas turbine is approximately 10 % of the nominal power, and the price is approximately 200 €/MWh. Based on the data from Fingrid’s gas turbines, the price for running the gas turbines on minimum power is 21 000 €/h, and the total amount of kinetic energy they provide is 6.2 GWs. Gas turbines are used for disturbance situations, so if part of this power is used for inertia purposes, some other capacity needs to be reserved for fast-disturbance reserve. The average price for this capacity is 4 €/MWh. In the end, the average price for inertia produced by gas turbines is approximately 3 500 €/GWs/h.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable.
- Ex-ante costs. The cost for running gas turbines on minimum power, just to provide extra inertia to the system, is about 3 500 €/GWs/h, based on the assumptions above, including fuel costs.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

The gas turbines, used by Fingrid and Svenska kraftnät primarily for fast-disturbance, could easily be used to provide rotating mass to the system. However, the activation cost are significant. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system is 20 GWs, whereas the potential is 6.2 GWs. As such, the rotating mass provided by gas turbines is not a sufficient mitigation measure for low-inertia situations.

8.1.4 INERTIA FROM THE PUMPS OF PUMP-STORAGE HYDRO POWER PLANTS

The 2012 Gothia report "Primary frequency control reserves from new producers" [14] includes a description of pumping facilities of Norwegian hydro plants. The 13 pumps (reversible turbines and non-reversible pumps) of 9 plants represent approximately 3 GWs of inertia, and a load of approximately 1 000 MW.

The report describes the pattern of operation of the pumps and, as can be expected, they run when spot prices are very low, in the spring and summer. These are typically low-inertia conditions, especially the hours of low spot prices. Therefore, with a short-term inertia forecast showing a need for low-inertia measures, the pumps are already expected to run, and there may be little more of real inertia to get from these resources. Still, all pumps may not be scheduled to run, and those that are not, could be an efficient sources of kinetic energy, given efficient incentive mechanisms.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable.
- Ex-ante costs. If pumps are started for inertia purposes when energy prices are insufficient incentives, then the "missing money" from the pumping for the energy market is a cost for the provider; as low-inertia conditions go along with low spot prices, the cost is low.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

There is in principle a potential of 3 GWs at a (missing money) cost set by the energy market. As the pumps are expected to run when the inertia is low, they cannot provide additional rotating mass; their practical potential is therefore close to zero.

8.1.5 REDUCE THE POWER OUTPUT OF NON-SYNCHRONOUS UNITS

The rotating mass in the system can be increased, by increasing the amount of synchronous generators that are running. This can be achieved by limiting the power from non-synchronous units, or by limiting the import, either in the planning phase (as a restriction in the clearing of the energy market), or in near real-time (as redispatch or special regulation). The first option would limit the energy market share of the non-synchronous generators such that the rotating mass is kept above some threshold that is deemed adequate. This means curtailing power from wind or solar generation, and replacing this power with flexible generation at a non-zero fuel cost. The

money flow would not involve the TSO. The second option implies the sale of scheduled energy from wind and solar power back to the market participants at a zero or maybe lower price, and the activation of reserves from synchronous producers such that more units and more rotating mass is started. The costs for the market participants are defined by fuel costs and energy market prices, and the socioeconomic costs are equal to the fuel costs of the added synchronous production. The TSO costs of redispatch would be roughly equal to the socioeconomic costs.

The potential is limited by the installed capacity of flexible production, and by the power demand, which is typically low when the inertia is low.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable.
- Ex-ante costs. Limiting the power from non-synchronous units, or limiting the import, in order to increase the amount of synchronous generators (and rotating mass) in the system, comes at a socioeconomic costs that equals the fuel costs of the added synchronous production.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

Limiting the power from non-synchronous units, or limiting the import, in order to increase the amount of synchronous generators (and rotating mass) in the system, comes at a socioeconomic costs that equals the fuel costs of the added synchronous production. The potential is limited by the installed capacity of flexible production, and by the power demand, which is typically low when the inertia is low. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 20 GWs.

8.2 DIMENSIONING INCIDENT

The Dimensioning Incident (DI) is the largest production unit, consumption unit, or interconnector in the system at a specific moment in time, that can be subject to an outage (the N-1). By reducing the amount of active power being produced, consumed, or transferred, the impact (frequency excursion) of this so-called DI can be limited.

8.2.1 DECREASE THE OUTPUT POWER OF THE LARGEST UNIT

The dimensioning incident in the system today, and many times in the future, consists of the largest nuclear production units. One mitigation measure is to limit the allowed power production of this largest unit. If this measure is utilized, the producer must receive market compensation for the costs associated with the power limitation. It is possible that more than one unit needs to limit its output. In Table 8-3 the largest production units in the Nordic power system are listed.

TABLE 8-3 LARGEST PRODUCTION UNITS IN THE NORDIC POWER SYSTEM

| Production Unit | Total generated power [MW] |
|-----------------|---------------------------------|
| Oskarshamn 3 | 1450 |
| Olkiluoto 3 | 1300 (1600 – 300) ¹⁸ |
| Forsmark 3 | 1235 |
| Ringhals 4 | 1130 ¹⁹ |
| Forsmark 2 | 1120 |
| Forsmark 1 | 1080 |
| Ringhals 3 | 1064 ¹⁹ |

The TSOs are responsible for the operation of the power system in the Nordics, and can give orders to all parties connected to the grid if the security of the system is in danger. These orders can be given for immediate actions, but also at a D-1, D-2, D-x stage. So the decrease of the output power of a power plant can be ordered by a TSO if the system security is in danger, for example in the case of very low inertia in the Nordic power system.

However, the decrease of power of a large unit is not a simple task. If the power production is decreased to a large extent, the substitutive power must be found either by starting some other production or by decreasing of consumption. Since the market has already been disturbed, the compensatory power cannot be launched market-based.

As seen in Table 8-3, the largest units in the Nordics are nuclear units. Decrease of the power output can technically be performed fairly rapidly; it will take some minutes. After every decrease of nuclear power, the effects of this action for the core needs to be calculated so that the safety margin is sufficient. It is possible that also some regulatory procedures are needed by safety authorities.

If the power of a nuclear unit is decreased, there will also be some economic impacts for the producer. Since the new power output level, after reduction, is not the power level that has been the basis for the operational planning, the efficiency will decrease. For example, if the planned power level has been 100 % (as it usually is for a nuclear power plant), the rule of thumb is that half of the fuel, that has not been used during the decreased power level, will be wasted. However, the fuel costs for nuclear power plants are fairly low, so the economic impact caused by this will be rather low.

The producer will face some economic impacts also after the power decrease, since it might take from six up to 72 hours to get the power output back to full power depending on how long the limitation for the nuclear unit's power production has lasted. It is also possible that the full power cannot be reached after the power decrease. For example, if the decrease of power output is

¹⁸ The impact of Olkiluoto 3 tripping will be reduced from 1600 MW to 1300 MW with a system protection scheme of 300 MW load.

¹⁹ Net power, without considering the house load.

performed after 80 % of the operational period (i.e. time between fuel loadings) has passed, some power plants cannot reach the full power during that operational period.

It should be taken into account that the decrease of the power of a nuclear unit is a state of change that causes a temperature transient. This transient will induce a cumulative aging of the unit and also increases the risk for failures.

The impact of power decrease on nuclear units has been studied and there is an estimate of 20–25 USD/MWh for the total costs for power regulation.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 120 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable.
- Ex-ante costs. The cost is analogous to the redispatch described above for limiting the non-synchronous production (Section 8.1.5). But the price difference is smaller in the case of a DI reduction, as the "largest unit" will be one using fuel at a non-zero cost. On the other hand, non-synchronous production is able to obtain the full power quickly after the limitation, while for nuclear power plants it will take several hours to return back to their original power after the limitation. The socioeconomic costs are equal to the price difference between the largest unit and the corresponding increased production from other units, multiplied by the volume of the restriction. This volume could be in the order of 2–400 MW for one large unit. If several large units are of DI size, then the necessary volume of the "redispatch" may be larger.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

Decrease of the power of the largest unit is technically an easy mitigation action for low-inertia situations. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 120 MW. From a cost point of view, this action will cause socioeconomic costs in the same way as limiting the power output of non-synchronous units; the reduction of the dimensioning incident comes at the full cost of the "redispatch". From a pure fuel cost consideration, it seems like a better option than the limitation of non-synchronous production, unless the DI is set by several units of roughly the same size.

8.2.2 DECREASE THE (PLANNED) IMPORT / EXPORT ON AN HVDC LINK

If the transmission on a HVDC link needs to be reduced in real-time operation, it can be done easily. The power deficit or surplus caused by this action can be taken care of by the Nordic balancing market.

If the decrease of the import or export on an HVDC link needs to be performed in coming days, the capacity on the HVDC link – provided to the day-ahead market – can be limited. Another option is not to limit the capacity, but to take care of the potential problem in real-time with the balancing market (on both sides of the DC link). However, the capacity limitation can be seen as a better solution, since it will give the possibility for market actors in the day-ahead market to find the optimum solution for that situation. The day-ahead market is a bigger market compared to the

balancing market, and the optimum found in the day-ahead market is probably better than the one in the balancing market.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 121 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation: Not applicable.
- Ex-ante costs. The socioeconomic cost is analogous to that of a restriction of the output power of the largest unit, as described in Section 8.2.1, considering the price difference across the HVDC link instead of the fuel costs. The reduction of the dimensioning incident comes at the loss of the congestion rent; this cost is socialized among the owners of the impacted interconnectors.
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

A decrease of the import or export on an HVDC link is technically an easy mitigation action for low-inertia situations. The socioeconomic cost is analogous to that of a restriction of the output power of the largest unit, considering the price difference across the HVDC link instead of the fuel costs. The reduction of the dimensioning incident comes at the loss of the congestion rent; this cost is socialized among the owners of the impacted interconnectors.

8.2.3 DECREASE POWER BEHIND SYSTEM PROTECTION

The dimensioning incident in the Norwegian grid is an outage that triggers the system protection scheme (SPS) in Hasle. The system protection scheme disconnects several production units if the units are activated, and a critical transmission line exporting from Norway to Sweden falls out. The operators at the national control centre in Norway activate the necessary production in the system protection scheme to be able to increase the capacity to Sweden and to avoid overload in case of outages. The dimensioning incident in Norway is 1 200 MW and for that reason, the operators cannot activate more than 1 200 MW production to the SPS.

It is important to notice that the SPS is active only when needed. The operators at the national control centre monitor a large number of cuts, which are combinations of lines that limit the transfer capacity. The national control centre activates more production on the system protection scheme when the cuts are full, and an outage will lead to an overload of components. When the flow on the cuts are lower, the operators deactivate units from the SPS.

To decrease the power behind the system protection scheme, either the capacity from Norway towards Sweden needs to be reduced, or special regulation needs to be utilized. The SPS in Hasle will be the dimensioning incident in Norway until the cables to Germany and England are finished within a couple of years. Please note that, also after the HVDC links are in operation, it is possible that the SPS in Hasle is the dimensioning incident in some operational situations.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 122 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable.
- Ex-ante costs. The socioeconomic cost is analogous to that of limiting the power output of non-synchronous units (Section 8.1.5), limiting the power output of the largest unit (Section 8.2.1), or decreasing the import or export of HVDC connections (Section 8.2.2).
- Ex-post costs. There are no extra costs materializing, in case an N-1 fault does occur during a low-inertia situation.

Conclusion:

Decrease of the power production behind system protection is a mitigation action already in use in Norway. From a cost point of view this action will cause socioeconomic costs in the same way as limiting the power output of non-synchronous units, limiting the power output of the largest unit, or decreasing the import or export of HVDC connections.

8.3 ACTIVE POWER

Instead of active power being extracted from the rotating mass in the system, active power can also be injected when needed to limit the frequency excursions, and to support the frequency restoration. Various options to do so are listed in the sections below.

8.3.1 PROVIDE EXTRA FCR-D

FCR-D has the objective of balancing large active power disturbances (like a loss of a generator) before critical frequency limits are violated. An example of such a limit is the under-frequency load shedding level. The revised FCR-D, currently being specified, is dimensioned so that the frequency deviation does not exceed 0.9 Hz after the dimensioning incident (1 450 MW) in the dimensioning system (120 GWs after DI). The dimensioning system is defined by its kinetic energy, frequency-dependent load, and FCR-D capacity. Therefore, additional measures need to be taken when, for example, kinetic energy decreases below the dimensioning level.

As argued in Section 3.2, instability may occur if the regulating strength is too high. The new requirements developed in the FCP-project introduce a stability margin, that allows additional regulating strength or reduced kinetic energy while remaining closed-loop stable. However, if the kinetic energy is reduced below 120 GWs, the continuous controlled FCR-D should be decreased in order to keep the closed-loop stability margin. Additional FCR-D provided as continuous control is not an alternative to mitigate frequency stability in reduced kinetic energy situations, if closed-loop stability margins are strictly to be respected.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 340 MW (current FCR-D performance; in the reference situation used for the simulations). Note that this additional capacity must be provided as step-wise linear control in order not to cause closed-loop instability. In fact, FCR-D provided as continuous-controlled reserve should be reduced from 1 450 MW to 967 MW in order to keep the closed-loop stability margin in the 80 GWs system. Non-continuously controlled FCR-D may replace the reduced volume of the continuously-controlled FCR-D. However, further studies may be needed to ensure that a high share of non-continuously controlled FCR-D provides acceptable responses.

Summary of costs:

- Implementation cost. Not applicable.
- Ex-ante cost. If extra capacity for FCR-D is reserved for the mitigation of low-inertia situations, this capacity is not available in other markets. If this extra capacity for FCR-D represents a fairly low-priced product in the energy markets, this reservation of extra FCR-D capacity will cause socioeconomic costs, since more expensive production needs to be activated.
- Ex-post cost. The energy costs for the activation of the extra FCR-D.

Conclusion:

An additional amount of FCR-D might be a mitigation tool for minimum-inertia situations. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 340 MW (current performance; in the reference situation used for the simulations). Note that this additional capacity must be provided as step-wise linear control in order not to cause closed-loop instability. In fact, FCR-D provided as continuous-controlled reserve must be reduced from 1 450 MW to 967 MW in order to keep the closed-loop stability margin in the 80 GWs system²⁰. As the additional FCR-D must be provided as step-wise linear control, it is possible that this kind of capacity is not provided by traditional FCR-D providers. The acceptable share of non-continuously controlled FCR-D must be further analysed in order to achieve acceptable responses. The costs related to this mitigation tool are related to the reserved capacity that is not available in other energy markets, and the cost for the activation of the extra FCR-D.

8.3.2 PROVIDE SYNTHETIC INERTIA

A controller which emulates the inertial response of a synchronously-connected generator can be included in a non-synchronously-connected production unit. The inertial response produced by such a controller is often referred to as a synthetic inertial response. Synthetic inertia is elaborated upon in Section 6.1. Synthetic inertia is controlled based on the rate of change of frequency. As measuring df/dt (RoCoF), is not a straightforward exercise, the practical application of synthetic inertia is still limited. Both synthetic inertia and FFR proportional to the frequency deviation, can be considered in the closed-loop stability analysis. They may add additional closed-loop stability margins or give headroom for additional continuously-controlled FCR-D.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system (in the reference situation used for the simulations): 337.5 MW (peak power at $df/dt = -0.404$ Hz/s). This is equivalent to 20 GWs.

Summary of costs:

- Implementation costs. Costs to adjust existing controllers to provide synthetic inertia.
- Ex-ante costs. Reservation of capacity to provide synthetic inertia.
- Ex-post costs. Activation costs of providing synthetic inertia.

Conclusion:

²⁰ Based on the project work performed by the Nordic TSOs within the framework of the FCP project

Synthetic inertia is controlled based on the rate of change of frequency. As measuring df/dt (RoCoF), is not a straightforward exercise, the practical application of synthetic inertia is still limited. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 337.5 MW (peak power at $df/dt = -0.404$ Hz/s); this is equivalent to 20 GWs. The cost for providing synthetic inertia is not clear.

8.3.3 PROVIDE FFR

When a low-inertia situation occurs, one of the potential mitigation measures is to activate FFR (see also Section 6.2). FFR can be provided from several sources and the control schemes may look different. FFR services can provide a change in power proportional to the frequency deviation or as a pre-determined scheme. The triggering of FFR impacts the effectiveness of the scheme and follows similar aspects as the triggering of EPC. Moreover, there are benefits and drawbacks with different control schemes.

A potential drawback with a pre-determined scheme is that there may be too much power activated, thus, the triggering is essential. In addition, the ramp back needs to be smooth in order not to cause a second instantaneous frequency deviation that is larger than the first. In order to utilize the source best, most energy should be injected before the maximum instantaneous frequency deviation occurs. The pre-determined scheme maximizes the injected energy as it is not influenced by natural frequency oscillations (exemplified in Figure 3-4), in the same way as the proportional control scheme. Both synthetic inertia and FFR proportional to the frequency deviation, can be considered in the closed-loop stability analysis. They may add additional closed-loop stability margins or give headroom for additional continuously-controlled FCR-D.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system (in the reference situation used for the simulations):

- FFR proportional to frequency deviation
148 MW (peak power at $\Delta f = -1.072$ Hz).
- FFR pre-determined scheme
130 MW (duration of 10 s).

Summary of costs:

- Implementation costs. Costs to adjust existing controllers to provide FFR.
- Ex-ante costs. Reservation of capacity to provide FFR.
- Ex-post costs. Activation costs of providing FFR.

Conclusion:

When a low-inertia situation occurs, one of the potential mitigation measures is to activate FFR. FFR services can provide a change in power proportional to the frequency deviation or as a pre-determined scheme. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 148 MW (peak power at $\Delta f = -1.072$ Hz) for the FFR proportional to frequency deviation, and 130 MW (duration of 10 s) for the FFR as a pre-determined scheme. Technical specifications of the FFR are not part of this report, and the cost for providing FFR is not clear.

8.3.4 PROVIDE EPC

Low-inertia situations can be mitigated by the use of EPC functionality on HVDC links, as described in Chapter 7. A redesign of the EPC settings, on a common basis, has a great potential to mitigate too low frequency excursions in the Nordic synchronous area in low-inertia situations. Some suggestions to alter the EPC settings are listed below:

- Use a high ramp rate (at least 100 MW/s). A high ramp rate is needed to inject the power before the frequency minimum is reached.
- Distribute the frequency triggers evenly among the different DC links, within a range of approximately 49.7–49.3 Hz. In that way the EPC will only activate when a severe disturbance occurs, and at the same time be able to affect the frequency minimum.
- There is no need to use too much volume per link (100 MW per link is fine). The important thing is to get the power in before the frequency minimum. There is no added value to feed in a lot of power after the frequency minimum.

An agreement with the TSO(s) of the other synchronous area is needed to alter the settings of the EPC.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 155 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Costs to adjust the EPC controller settings.
- Ex-ante costs. If the availability of EPC is secured by reserving HVDC capacity, this can cause costs for market actors.
- Ex-post costs. At the moment there is no cost linked to the activation of EPC. It is possible that there will be a compensation for activated power and/or energy in the future.

Conclusion:

In Chapter 7, EPC has already been demonstrated to be a very effective low-inertia mitigation measure. Market simulations show that for situations with low kinetic energy, there is assumed to be EPC power available. A redesign of the EPC settings has been proposed to make it more efficient. EPC is the cheapest measure for dealing with low-inertia situations. Please keep in mind that the work on EPC, and HVDC links between synchronous areas, is addressed by an ENTSO-E Working Group in the light of the System Operation Guideline (frequency coupling part) [15].

8.3.5 REDUCE LOAD

Load reduction can provide active power in different ways, to mitigate low-inertia situations, such as:

- In one or more steps as FCR, FFR, or other products
- Triggered by frequency, RoCoF, or remote control
- As aggregated load, or direct
- With a long, or short duration of disconnection

Sources can be industrial loads, pump-storage hydro (addressed below), and – in the future – commercial and smaller loads that are aggregated.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 130 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Equipment for activation, remote control, and aggregation. Large-scale aggregation of small loads is probably not justified for inertia purposes.
- Ex-ante costs. Sudden disconnection of loads for the benefit of the power system would have an impact on the usefulness of electricity for the consumer. Flexibility contracts could be designed with consumers opting in or out, depending on the compensation. Implementation could be easy for industrial loads, but at higher standby costs than commercial and residential loads. Aggregated loads could have considerable aggregation costs.
- Ex-post costs. The direct cost for the provider is the energy imbalance cost. Indirect costs and other costs could be related to wear and tear. Industrial loads might have activation costs in addition to the energy costs, if the disruption of electricity has additional impacts on the industrial process; Aluminium production is a good example. Activation costs would be much higher than just the energy costs.

Conclusion:

Load reduction is an efficient mitigation measure for low-inertia situations. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 130 MW. The cost for providing load disconnection is not clear.

Disconnection of pumps for hydro storage

Pumps used for pumped-storage hydro plants are a particularly interesting source of load disconnection. As explained in Section 8.1.4, in Norway 13 pumps (reversible turbines and non-reversible pumps) of 9 plants represent approximately 3 GWs of inertia, and a load of approximately 1 000 MW. The pumps run when spot prices are very low, being typically low-inertia conditions. As such, little additional inertia can be expected from pumps when the system inertia is expected to be low, but the pumps could be efficient providers of FFR in the sense of load reduction.

Needed volume to affect the minimum frequency by 0.1 Hz in an 80 GWs system: 130 MW (in the reference situation used for the simulations).

Summary of costs:

- Implementation costs. Not applicable on source level, if the generator breakers are used for the disconnection. The need for implementation of an activation based on frequency, RoCoF, or protection relays is not analysed.
- Ex-ante costs. Not applicable, or a moderate cost that could be offered by competing providers of load disconnection.
- Ex-post costs. The direct cost for the provider is the energy imbalance cost. Indirect costs could relate to overflow, if water cannot be pumped from a full reservoir in a cascade of

plants along a river. Other costs are related to wear and tear (some types of pumps are not fit for frequent start/stop) and risk of overflow downstream of the pump.

Conclusion:

Load reduction is an efficient mitigation measure for low-inertia situations; the disconnection of pumps for hydro storage being a particularly interesting example. In Norway 13 pumps (reversible turbines and non-reversible pumps) of 9 plants represent approximately 3 GWs of inertia, and a load of approximately 1 000 MW. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system equals 130 MW. The cost for the disconnection of pumps for hydro storage is not clear.

8.4 OVERVIEW OF THE MITIGATION MEASURES

The different mitigation measures are, for a quick overview, summarized in the tabular overview on the next page.

| Mitigation Type | Mitigation Measure | Already in use today? (potentially for other purposes) | Measure available today in real-time operations (15 min)? | Measure available today in planning process (D-x, D-2, D-1)? | Notes | Potential in terms of GWs or MW volumes | Effectiveness the volume of the mitigation measure needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system | Sufficient Is only this measure sufficient to mitigate low-inertia situations? Combines the effectiveness and the potential | Availability Is this source/measure always available? | Implementation costs The implementation costs cover the necessary preparation for capacity, including control, configuration, and prequalification | Ex-ante costs Ex-ante costs are related to the actions that need to be taken just to prepare that an N-1 fault can happen during minimum-inertia situations | Ex-post costs Ex-post costs materialize in case an N-1 fault does occur during a low-inertia situation |
|------------------------------------|--|---|---|--|--|--|---|---|--|--|---|--|
| | | | | | | | | | | | | |
| Dimensioning incident | Decrease the output power of the largest unit | Yes, the TSO can request to reduce power in case of SoS issue | Yes | Yes | Forced decrease of power will violate the market, cause losses for the producer, and increase the risks for failures. | Power can be reduced to the level of the next highest unit or the power of several units can be reduced to the needed level. | 120 MW | Yes | Yes | NA | *redispach* costs and costs for the producer due to lost energy and decreased efficiency. | NA |
| | Decrease the (planned) output on an HVDC link | Yes | Yes: countertrade or loop flow | Yes: limit the DC capacity provided to the energy market | Controversial. Market regulation and owners of interconnectors want to maximize benefits of trade. | Power can be reduced to the level of the next highest N-1, or the power of several links can be reduced to the needed level. | 121 MW | Yes | Yes | NA | *redispach* costs | NA |
| | Decrease power behind system protection | Yes | Yes | Yes | Protection schemes are the dimensioning incident in Norway | Reduction to the next dimensioning incident. | 122 MW | In principle | Yes | NA | *redispach* costs | NA |
| | Run (units as) synchronous condensers GAS | Yes | Yes | Yes | For some units, technical adjustment needed before being available | For some units, technical adjustment needed before being available | 20 GWs | No | Yes: gas units are expected to be idle in times of low inertia. | NA | For some units, technical adjustment needed before being available | replacement costs |
| Roaming mass | Run (units as) synchronous condensers HYDRO | No | NA | NA | Technical adjustment needed before being available | 25 GWs | Yes | Yes | Yes: Pelton turbines are expected to be idle in times of low inertia. | 0.27-0.33 €/MWh (if the unit/plant is not equipped with suitably-sized penstock led system) | 0.27-0.33 €/MWh (if the unit/plant is not equipped with suitably-sized penstock led system) | NA |
| | Reduce / limit power output of non-synchronous units to have more synchronous units online | No | NA | NA | Against policies and expectations to curtail windpower. How to select units for reduction? For redispach, mFRR bids are used. Wind power is not offering mFRR yet. | 20 GWs | ? | ? | Varying availability, e.g. depending on wind | NA | *redispach* costs | NA |
| | Start up generators and run them at low output power (against the DA price signals) | Yes, for voltage control and the FCR and aFRR markets | Maybe, as redispach based on mFRR bids. | NA | NA | More generic: possibility to have one unit running at 80%, to have two units running at 40% instead | 20 GWs | No | Varying availability, depending on scheduled flexible generation. This may be low in hours of import and low load. | NA | 3500 €/GWh (the numbers refer to the use of the FG gas units) | NA |
| Active Power | Activate pump storage | No | NA | NA | Pumps will probably run in low-inertia situations | 0-3 GWs | 20 GWs | No | No, the pumps will probably be running already when more inertia is wanted | NA | *Missing money* cost, set by the energy market | NA |
| | Provide synthetic inertia | No | NA | NA | Possible from HVDC, wind, battery as long as measuring RoCoF is not straightforward | ? | 337.5 MW (peak power at $\Delta f = -0.404$ Hz/s). Equal to: 20 GWs | ? | ? | Control equipment | Reservation of capacity | Activation cost |
| | Provide FFR (proportional) | No | NA | NA | Possible from HVDC, wind, battery and so on | ? | 148 MW (peak power at $\Delta f = -1.072$ Hz) | Yes | Always (assuming some flexible load in the system) | Control equipment | Reservation of capacity | Activation cost |
| | Provide FFR (pre-determined) | No | NA | NA | Possible from HVDC, wind, battery and so on. Too much pre-determined activation (step) without feedback can cause a second nadir lower than the first | ? | 130 MW (10 s duration) | Yes | Always (assuming some flexible load in the system) | Control equipment | Reservation of capacity | Activation cost |
| | Provide EPC | Yes | Yes | Yes | Current EPC settings would need to be altered to be efficient | Extra FCR-D is not an option due to the stability margin in the system | 155 MW (1 link), with a ramp rate of 100 MW/s | Yes | Yes | Yes | Current EPC controller settings would need to be altered | Possible reservation of HVDC capacity |
| Provide extra FCR-D | Yes | No, has to be procured ex-ante. | Yes | Yes | Extra FCR-D is not an option due to the stability margin in the system | ? | 340 MW | No, for stability reasons | Yes | NA | Reserved capacity, not available in other energy markets | Activation cost |
| Reduce load | Yes | ? | ? | ? | ? | 130 MW | Yes | Always (assuming some flexible load in the system) | Control equipment | Reservation of capacity | Reservation of capacity | Energy imbalance, wear and tear |
| Disconnect pumps for hydro storage | No | NA | NA | NA | Normally running in low-inertia situations | 1000 MW | 130 MW | Yes | Always, as the pumps are expected to run in typical low-inertia situations. | NA | NA | Energy imbalance, wear and tear |

8.5 MULTI-CRITERIA ASSESSMENT (MCA)

The different mitigation measures as described in this chapter are evaluated on the basis of a Multi-Criteria Assessment (MCA). In an MCA, the different mitigation measures are scored on the basis of criteria, such in order to get a grip on the most promising ones. In this case the focus is on the most promising mitigation measures to be applied in 2020.

As the criteria can be quite diverse, e.g. the cost of a measure or its efficiency, the scoring is done in terms of discriminating the mitigation measures among themselves for each criterion, by labelling them to be either: most promising (+), neutral (0), or poor (-). Although it is inevitable that, in this way, we are comparing apples with pears, the objective of the MCA is to do this comparison in a transparent way. The MCA is shown Table 8-4.

TABLE 8-4 MCA

(+: MOST PROMISING, 0: NEUTRAL, -: POOR. AS AN EXAMPLE, A “+” FOR THE COST ASPECT INDICATES A LOW COST)

| Mitigation type | Mitigation measures | Potential, effectiveness, sufficient | Cost | Available in 2020? |
|--|--|--------------------------------------|------|--------------------|
| Dimensioning incident (Section 8.2) | Decrease the output power of the largest unit | + | - | Yes |
| | Decrease the (planned) import/export on an HVDC link | + | - | Yes |
| | Decrease power behind system protection | + | - | Yes |
| Rotating mass (Section 8.1) | Run (units as) synchronous condensers - GAS | - | 0 | Maybe |
| | Run (units as) synchronous condensers - HYDRO | + | 0 | Maybe |
| | Reduce / limit power output of non-synchronous units to have more synchronous units online | - | - | Maybe |
| | Start up generators and run them at low output power (against DA price signals) | - | - | Yes |
| | Activate pump storage | - | 0 | Yes |
| Active power (Section 8.3) | Provide synthetic inertia | 0 | 0 | No |
| | Provide FFR | + | 0 | Maybe |
| | Provide EPC | + | + | Yes |
| | Provide extra FCR-D | - | 0 | Yes |
| | Reduce load | + | 0 | Yes |
| | Disconnect pumps for hydro storage | + | 0 | Yes |

The most promising options (in terms of potential, effectiveness, and being sufficient), that can be available in 2020, are marked grey in Table 8-4. The reduction of the dimensioning incident, a measure already existing today, scores low in terms of cost and can be seen as a “plan B”.

The “plan A” mitigation measures – being most promising in terms of potential, effectiveness, being sufficient, and cost that can be available in 2020 – consist of active power injections. The active power injection can be realized by:

- EPC
EPCs are in use already today; a redesign of the EPC settings has been proposed to make it a more efficient mitigation measure. In this respect, please keep in mind that the work on EPC, and HVDC links between synchronous areas, is addressed by an ENTSO-E Working Group in the light of the System Operation Guideline.
- Load disconnection
Loads are participating to the FCR-D already today. It may be those loads that could be utilised for mitigating minimum-inertia situations as well, though some changes might be needed for their settings.
- Disconnection of pumps for hydro storage
Being a special case of the load disconnection.

In order to deal with the low-inertia situations in the year 2020, as forecasted in Chapter 5, it is those measures that are proposed to be implemented before 2020, in a next step of the project, thereby developing a toolbox to deal with low-inertia situations in the Nordic synchronous area. Also the development of the new FFR product needs to be continued, as a potential new measure in this toolbox. Indeed, the load disconnection, and EPC, may be defined as being FFR products, but other products – providing a fast power injection to the system – may be defined as well.

9. IMPROVEMENT OF INERTIA ESTIMATION AND OPERATIONAL TOOLS

9.1 INTRODUCTION

In this chapter of the report, the focus is on the means to estimate the inertia in the power system, and the models using this information to predict the potential frequency deviation in case of a dimensioning incident in the system.

In this respect, we can make a distinction between real-time, or online, tools (the SCADA/EMS system), and offline tools as shown in Table 9-1.

TABLE 9-1 ONLINE AND OFFLINE TOOLS

| | Online tools | Offline tools |
|----------------|---|---|
| 'Observations' | Kinetic energy estimation (Section 9.2) | |
| Forecasts | Frequency deviation (Section 9.3) | Kinetic energy estimation (Chapter 5, and Section 9.4) Frequency deviation (Section 3.3) |

Where the development of the frequency deviation forecast tools are initiated in an offline environment, the objective is to have them transferred to the online environment as well, being fed by real-time information. This approach is illustrated in Figure 9-1.

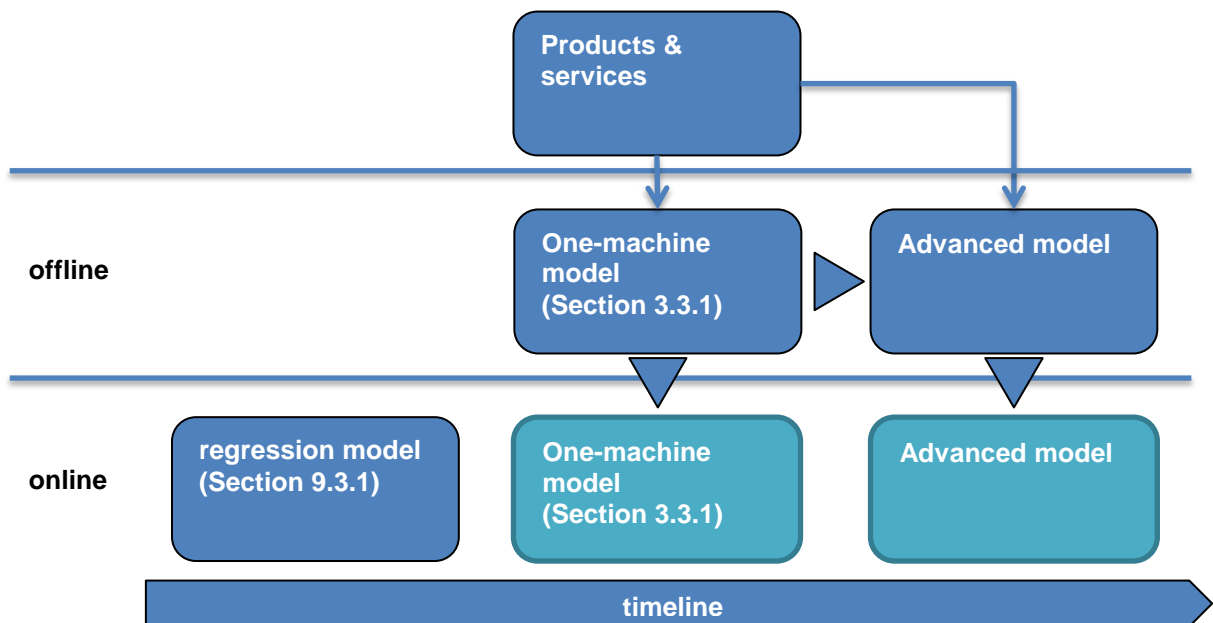


FIGURE 9-1 DEVELOPMENT OF TOOLS TO FORECAST THE FREQUENCY DEVIATION

9.2 ONLINE INERTIA ESTIMATION

All Nordic TSOs have implemented a kinetic energy estimation in their SCADA/EMS. This has been elaborated upon in the Nordic report on Future System Inertia [2].

Kinetic energy in the Nordic system can be estimated with the help of the circuit breaker (CB) positions of production units. When a generator circuit breaker position is closed, it is assumed that the generator can contribute to the kinetic energy of the system. The kinetic energy $E_{k,sys}$ of the system can then be calculated according to Equation (3.4), which is rewritten here for convenience:

$$E_{k,sys} = \sum_{i=1}^N S_{ni} H_i \text{ [GWs]} \quad (9.1)$$

where the inertia constant H_i and the rated apparent power S_{ni} for generator i is retrieved from a generator register, and N is the number of connected generators.

If the circuit breaker status is not available in the SCADA system, power measurements can be used to indicate which machines are synchronized to the system. If the generator power measurement is above a certain non-zero threshold value, it implies that the generator is synchronized to the system.

As some TSOs' SCADA systems undergo upgrades, or are in the process of being replaced, the work in this report focuses on the improvements that are foreseen to be made in the online kinetic energy estimation for each TSO, rather than on the actual implementations.

9.2.1 IMPROVEMENTS OF THE ONLINE ESTIMATION OF ENERGINET

Energinet installed a new SCADA system end 2015 / early 2016. The status quo of the Energinet online kinetic energy estimation is captured in Table 9-2. As all generators are already monitored, there is no room for improvement.

TABLE 9-2 STATUS QUO OF THE ENERGINET ONLINE KINETIC ENERGY ESTIMATION

| | Generation capacity included in the kinetic energy estimate [% of installed power] | | | Generators monitored by CB status | | Generators monitored by MW output | | Generators not monitored | | Generation monitored down to voltage level [kV] |
|--|--|-----------------------------|-------|-----------------------------------|----------------------|-----------------------------------|----------------------|--------------------------|----------------------|---|
| | By monitoring the CB status | By monitoring the MW output | Total | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | |
| Status quo of the online kinetic energy estimation | 82 | 18 | 100 | 25 | 15.8 | 22 | 3.5 | 0 | 0 | 10 |

9.2.2 IMPROVEMENTS OF THE ONLINE ESTIMATION OF FINGRID

The status quo and improvement potential of the Fingrid online kinetic energy estimation is captured in Table 9-3.

TABLE 9-3 STATUS QUO AND IMPROVEMENT POTENTIAL OF THE FINGRID ONLINE KINETIC ENERGY ESTIMATION

| | Generators monitored |
|---|----------------------|
| | Kinetic energy [GWs] |
| Status quo of the online kinetic energy estimation | 74.2 |
| Improvement potential (target value at the end of 2017) | 76.2 |

Sixteen active power measurements, where one measurement includes more than one generator, are used by the tool. These lumped measurements are planned to be exploded into individual generator measurements in order to improve the accuracy of the kinetic energy estimate.

9.2.3 IMPROVEMENTS OF THE ONLINE ESTIMATION OF STATNETT

Statnett is in the process of replacing its SCADA system during 2017 / 2018. In the current SCADA system, the online kinetic energy estimation is based on the total production level in each of eight consumption areas, scaled with an average inertia constant, 3.44 s, factor for inertia, operation point, and power factor. In the new SCADA system, individual generator circuit breaker positions combined with individual inertia values will be used to estimate the kinetic energy. The status quo and improvement potential of the Statnett online kinetic energy estimation is captured in Table 9-4.

TABLE 9-4 STATUS QUO AND IMPROVEMENT POTENTIAL OF THE STATNETT ONLINE KINETIC ENERGY ESTIMATION

| | Generation capacity included in the kinetic energy estimate [% of installed power] | | | Generators monitored by CB status | | Generators monitored by MW output | | Generators not monitored | | Generation monitored down to voltage level [kV] |
|--|--|--|-------|-----------------------------------|----------------------|-----------------------------------|----------------------|--------------------------|----------------------|---|
| | By monitoring the CB status | By monitoring the MW output | Total | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | |
| Status quo of the online kinetic energy estimation | 0 | 100 | 100 | NA | NA | 100 % | (~32 * 3,44) = 110 | NA | NA | NA |
| Improvement potential (target value) | 90 | Market plans used for the remaining 10 % | 100 | 2 300 | ~110 | NA | NA | - | - | All units in the market are included |

9.2.4 IMPROVEMENTS OF THE ONLINE ESTIMATION OF SVENSKA KRAFTNÄT

The status quo and improvement potential of the Svenska kraftnät online kinetic energy estimation is captured in Table 9-5.

TABLE 9-5 STATUS QUO AND IMPROVEMENT POTENTIAL OF THE SVENSKA KRAFTNÄT ONLINE KINETIC ENERGY ESTIMATION

| | Generation capacity included in the kinetic energy estimate [% of installed power] | | | Generators monitored by CB status | | Generators monitored by MW output | | Generators not monitored | | Generation monitored down to voltage level [kV] |
|--|--|-----------------------------|-------|-----------------------------------|----------------------|-----------------------------------|----------------------|--------------------------|------------------------------|---|
| | By monitoring the CB status | By monitoring the MW output | Total | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | Number | Kinetic energy [GWs] | |
| Status quo of the online kinetic energy estimation | 81.7 | 0 | 81.7 | 437 | 158.6 | 0 | 0 | – | 18.68 (assumption: $H = 3$) | 70 |
| Improvement potential (target value) | 83 | 0 | 83 | 450 | 160 | 0 | 0 | – | 17 | 70 |

9.2.5 TESTS TO VALIDATE THE ONLINE INERTIA ESTIMATION TOOL

The inputs to the online inertia estimation tool are associated with uncertainties and errors, as not all generators are monitored by the tool, and the inertia-constants used to calculate the generators' kinetic energies are associated with uncertainties as well. In addition, the kinetic energy from loads is not captured by the tool. Therefore, a need to validate the results provided by the tool exists.

An ideal way to validate the results would be to excite the power system with a known/measurable power imbalance (for example, a trip of a generator, or HVDC-connection to another synchronous area), to measure the system frequency, and from these quantities to calculate the system inertia during the event. However, as found out in the previous phase of the project, the current frequency-measurement-based inertia estimation methods are not accurate enough [2].

Frequency-measurement-based inertia estimation methods are, at the time of writing, being further developed in the European Union's Horizon 2020 research project MIGRATE²¹, where the goal is to develop a method for estimating area inertia, i.e. to divide the power system into smaller areas and estimate the inertia of these smaller areas. If successful, the method being developed could be used to validate the inertia estimates provided by the online inertia estimation tool.

Another approach to validate the estimates is to set-up a simulation case so that it accurately mimics the behaviour of frequency (during the first few seconds of a generator or HVDC trip event) in different parts of the power system during an actual event. The kinetic energy in such a

²¹ For more information about MIGRATE project, see <https://www.h2020-migrate.eu/>

simulation case could then be compared against the one provided by the online inertia estimation tool. Such simulation case needs to be tuned accurately, to depict the actual behaviour of the power system during the event. This requires a lot of work but the Common Grid Model being developed at the time of writing, could serve as a good basis for such a simulation case. The recommendation is to perform such validation as it will provide valuable information on the accuracy of the dynamic power system models currently being used, also from other perspectives than inertia.

9.3 ONLINE FREQUENCY DEVIATION ESTIMATION

9.3.1 LINEAR REGRESSION MODEL

In Section 3.1.3, the dynamic behaviour of an individual synchronous turbine-generator i has been described using the motion equation of a rotating mass (the swing equation):

$$H_i \frac{df_i}{dt} = \frac{f_n^2}{2S_{ni}f_i} (P_{mi} - P_{ei}) \quad (9.2)$$

where f_i is the frequency of generator i , f_n is the nominal frequency, P_{mi} is the mechanical power of turbine-generator i , and P_{ei} is the electrical power of generator i . As we are mainly interested in the frequency deviation from the pre-disturbance frequency to the frequency extreme (Figure 3-5), that we assume to be equal to the nominal frequency ($\Delta f_i = f_i - f_n$), we can write equation (9.2) as follows:

$$H_i \frac{d\Delta f_i}{dt} = \frac{f_n^2}{2S_{ni}f_i} (P_{mi} - P_{ei}) \quad (9.3)$$

If we generalize equation (9.3) to a system level, with multiple generators, the following equation results:

$$\frac{d\Delta f}{dt} = \frac{f_n}{2S_{n,sys}H_{sys}} \Delta P = \frac{f_n}{2} \frac{\Delta P}{E_{k,sys}} \quad (9.4)$$

This implies that a linear relation may be observed between the RoCoF and the ratio $\Delta P/E_{k,sys}$. By assuming a linear relationship between the RoCoF and the f_{extreme} it is possible to estimate the frequency deviation after a disturbance:

$$f_{\text{extreme}} = k \frac{\Delta P}{E_{k,sys}} + m \quad (9.5)$$

where k and m are calculated using data from historical disturbances, where f_{extreme} (Hz), $E_{k,sys}$ (MWs), and the ΔP (MW) are known.

A linear regression analysis has been performed in order to find the best fit of the model with the disturbance data in a roughly one-year period (from 2015-07-20 to 2016-09-28), consisting of 19 under-frequency, and 26 over-frequency cases as shown in Figure 9-2.

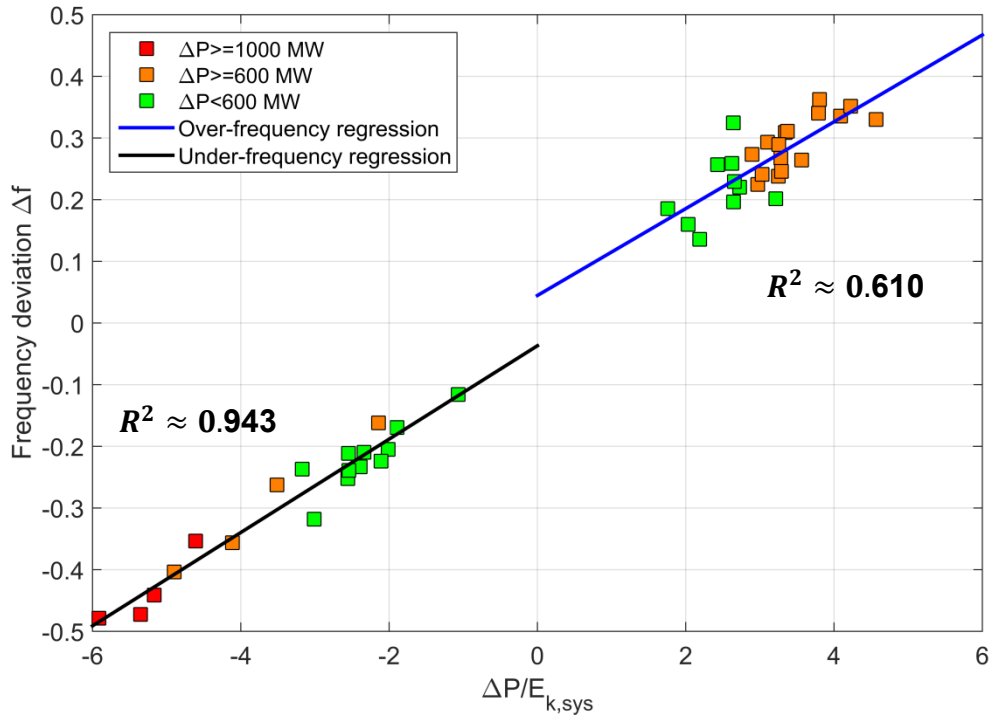


FIGURE 9-2 LINEAR REGRESSION ANALYSIS BASED ON 45 MEASURED DISTURBANCES

The resulting model fits are:

$$\Delta f_{\text{under-frequency}} = 0.07570 \cdot \frac{\Delta P}{E_{k,\text{sys}}} - 0.03690 \quad (9.6)$$

$$\Delta f_{\text{over-frequency}} = 0.07041 \cdot \frac{\Delta P}{E_{k,\text{sys}}} + 0.04463 \quad (9.7)$$

where ΔP is provided in MW (being a positive value for over-frequency and a negative value for under-frequency situations), and the $E_{k,\text{sys}}$ is in GWs.

9.3.2 SCADA IMPLEMENTATION

The linear regression model, described in Section 9.3.1, allows for an online f_{extreme} estimation, in case of a dimensioning incident in the system. Indeed, the system kinetic energy ($E_{k,\text{sys}}$) is estimated in the SCADA systems (see also Section 9.2), whereas the online dimensioning incident determination (ΔP) has been implemented in the SCADA systems as well, within the framework of this project.

The online f_{extreme} estimation tool calculates the frequency extreme for every contingency in the Nordic power system that could result in active power disturbance larger than 300 MW. Inputs to

the tool are the current system frequency, the kinetic energy, and the active powers of the contingencies. Also, the possible kinetic energy reduction due to the contingency (in case of a generator trip) is taken into account. Based on the inputs, the frequency extreme is calculated for every contingency and the smallest (frequency nadir) and the largest (frequency zenith) values are displayed and stored. This enables the control centre operators to see what would be the frequency extreme if an N-1 contingency were to occur, and whether the frequency limits would be violated in case of an N-1 contingency.

We need to realize though that the model is limited in its application; indeed, it is tuned by a restricted amount of disturbances, where the number of extreme cases (with low frequency minimums) are relatively limited. A limitation of the model is the assumption of a linear relationship between the RoCoF and the f_{extreme} . In that way changes to EPC and FCR-D, due to operational conditions, (affecting the relation between RoCoF and f_{extreme}), is not handled in the model. To keep the accuracy of the model, the model needs to be updated periodically with the latest disturbances. In that way, major changes in the frequency control are taken into account.

The online f_{extreme} estimation tool was made operational on June 1, 2017. Since the tool was made operational to the time of writing this report, six frequency disturbances – where the frequency deviation was at least 0.3 Hz – have occurred. The disturbances, together with the actual and the estimated frequency extremes are shown in Table 9-6. The error in the estimate together with kinetic energy during the disturbance and size of the disturbance are also shown.

TABLE 9-6: ESTIMATED AND ACTUAL FREQUENCY EXTREMES

| Time (CET) | Cause | $E_{k,\text{sys}}$ (GWs) | ΔP (MW) | f_{extreme} actual (Hz) | f_{extreme} estimated (Hz) | f_{error} (Hz) |
|------------------|---------------|-----------------------------|--------------------|-------------------------------------|--|----------------------------|
| 06-06-2017 05:36 | NorNed HVDC | 152 | -493 | 49.72 | 49.74 | -0.02 |
| 06-13-2017 03:55 | NorNed HVDC | 145 | 729 | 50.36 | 50.36 | 0.00 |
| 06-27-2017 21:33 | NorNed HVDC | 172 | 729 | 50.35 | 50.32 | 0.03 |
| 07-14-2017 08:56 | Nuclear unit | 179 | -449 | 49.72 | 49.71 | 0.01 |
| 07-23-2017 20:28 | NordBalt HVDC | 165 | 733 | 50.30 | 50.33 | -0.03 |
| 09-02-2017 17:53 | NorNed HVDC | 168 | 617 | 50.25 | 50.24 | 0.01 |

As shown in the table, the largest error in the estimate (f_{error}) was 30 mHz which can be considered to be very good.

On September 17 2017, the Nordic TSOs performed very fast active power changes on the Great Belt HVDC-link in order to study the system response. The results are summarized in Table 9-7. The error in the estimate, together with the kinetic energy during the disturbance and the size of the disturbance are also shown.

TABLE 9-7: ESTIMATED AND ACTUAL FREQUENCY EXTREMES DURING THE GREAT BELT TEST

| Time (CET) | $E_{k,\text{sys}}$ (GWs) | ΔP (MW) | f_{extreme} actual (Hz) | f_{extreme} estimated (Hz) | f_{error} (Hz) |
|------------------|-----------------------------|--------------------|-------------------------------------|--|----------------------------|
| 09-17-2017 03:22 | 143 | -300 | 49.71 | 49.71 | 0.00 |
| 09-17-2017 04:17 | 142 | -573 | 49.60 | 49.54 | 0.06 |

As the table shows, during this test the largest error in the estimate (f_{error}) was 60 mHz which still can be considered to be good.

9.4 KINETIC ENERGY ESTIMATION

In Chapter 5, a simulation chain was presented, and validated, to assess kinetic energy in future scenarios (depicted on the top in Figure 9-3).

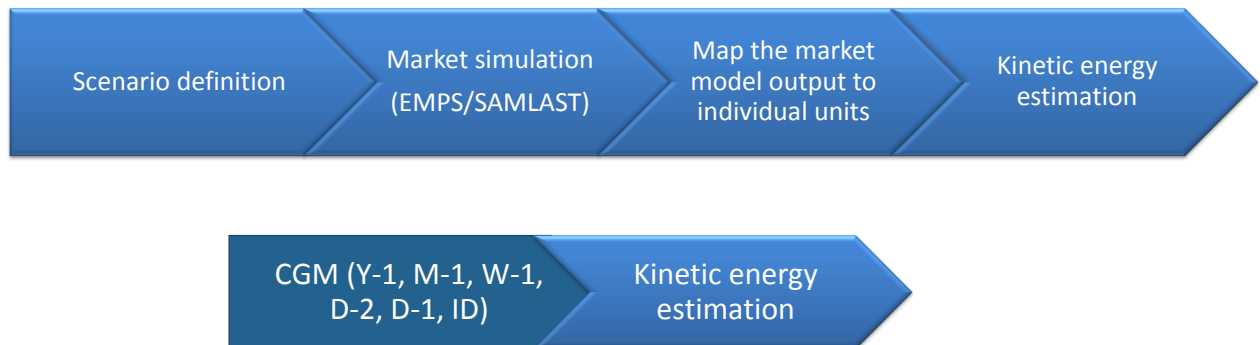


FIGURE 9-3 THE USE OF CGMs FOR KINETIC ENERGY ESTIMATION

The first three steps in this chain, lead to a forecast of power produced by individual generation units, of which the inertia constant are known, so that an estimate of the kinetic energy in the system can be computed. With the work on the Common Grid Model (CGM) ongoing, at the time of writing this report, it is exactly that information (forecast of power produced by individual generation units and their inertia constants) that will be available for the time frames targeted by the CGMs: Y-1, M-1, W-1, D-2, D-1, and ID. This is depicted in the lower part of Figure 9-3.

With the CGM being the best estimate of the grid for the targeted time frame (incl. generation, load, topology, and exchanges over DC links), it provides a perfect basis for a kinetic energy forecast for the following time frames: Y-1, M-1, W-1, D-2, D-1, and ID.

10. CONCLUSIONS AND FUTURE WORK

10.1 CONCLUSIONS

The Nordic TSOs have studied inertia-related issues in their project 'Future Inertia' phase 1 [2]. The work, started in phase 1, has been continued in the second phase of the project, of which the findings and results are described in this report.

The objectives of the Future System Inertia 2 project are to anticipate and to avoid the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures (see Figure 10-1).

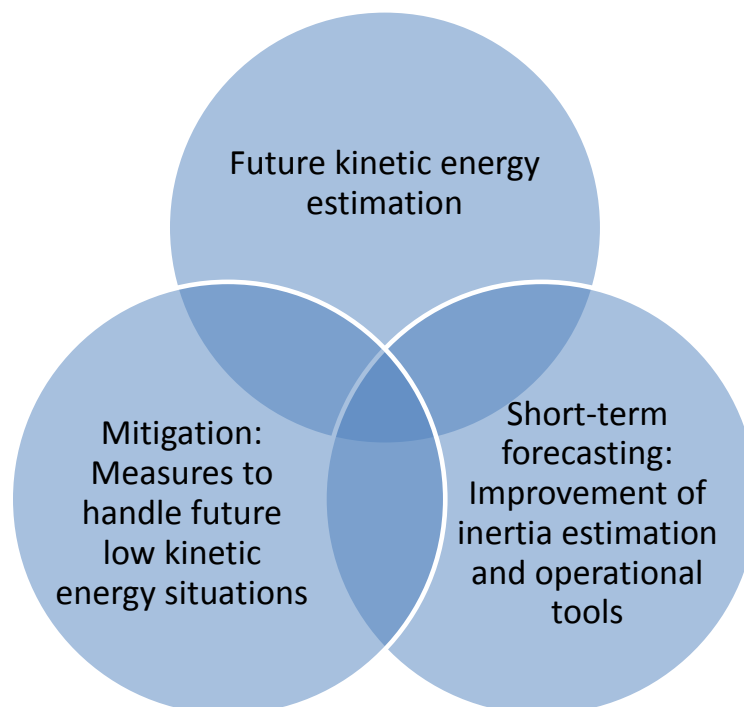


FIGURE 10-1 OBJECTIVES OF THE FUTURE SYSTEM INERTIA 2 PROJECT

The structural changes identified in the Nordic power system are not unique, and similar changes are occurring in other systems. Small and medium-sized synchronous systems are likely to already have experience and knowledge how to handle the challenges. To benefit of the experience gained, a survey was sent out by the Nordic transmission system operators (TSOs) during the summer of 2016, with a result of 11 answers. More than half of the synchronous systems under survey (eight out of 12) indicated that the decreasing inertia is a challenge. Three systems indicate that they have no solution in place for dealing with low-inertia situations at the moment. Two systems have market-based solutions, while six systems have non-market-based solutions. The existing solutions can be classified in different groups based on the techniques used:

- Increasing reserves (generation and load)
- Having some kind of operational limits for the system such as a minimum kinetic energy, limiting the flow on weak AC interconnections, ensuring that the RoCoF does not increase

after a generator loss, or imposing power limitations to avoid UFLS caused by a single contingency, and dispatch constraints linking the maximum HVDC import with the minimum system inertia

- Running at almost idle or minimum power with hydro or thermal units
- Contracted load disconnections as primary reserve using load under-frequency relays (note that all systems have under-frequency load shedding)
- Running hydro units in synchronous condenser mode
- Using frequency control SPS (FCSPS) that reduces the size of the largest contingency by tripping the required amount of load/generation

For dealing with future low-inertia situations, more reserves, synthetic inertia (as an ancillary service for example), more flexible thermal units, adding connections to other synchronous systems, and services from battery storage, are mentioned as foreseen mitigation measures.

In order to assess the impact of the changes ongoing and foreseen on the kinetic energy in the system, future market scenarios have been defined by the Nordic TSOs for the years 2020 and 2025. These market scenarios were input for market simulations, where the power production and corresponding market prices have been simulated, based on data corresponding to different inflow years. In this way, we obtained a forecast of the generation units that will be producing power in the years 2020 and 2025. Those generation units, of which the inertia constant is known, bring inertia into the system, and an estimate of the kinetic energy in the system has been computed.

In the year 2025, the total variation in kinetic energy values appears to be smaller than in 2020: the minimum values are higher than in 2020, and the maximum values are lower than in the year 2020. The difference between the forecasts of the two years can be seen from the probabilities of having a low-kinetic energy situation. In Table 10-1, the column with the 99 percentile, for example, indicates that in one percent of the time, the kinetic energy falls below the 120 GWs in 2020, and below 134 GWs in 2025.

TABLE 10-1: PROBABILITY OF HAVING A LOW-KINETIC ENERGY (GWs) SITUATION
THE COLUMN WITH THE 99 PERCENTILE, FOR EXAMPLE, INDICATES THAT IN ONE PERCENT OF THE TIME, THE KINETIC ENERGY FALLS BELOW THE 120 GWs IN 2020, AND BELOW 134 GWs IN 2025.

| Year | Kinetic energy in GWs below a percentile of the forecasted kinetic energy distribution | | |
|------|--|------|------|
| | 90 % | 95 % | 99 % |
| 2020 | 150 | 136 | 120 |
| 2025 | 159 | 147 | 134 |

Those results can be explained from the fact that the scenario 2025 has approximately 2 500 MW more system load compared to 2020. The increased load requires more production and not all is covered by wind and import. That also results in more synchronous production and thereby higher inertia. Another explanation to the increased inertia in 2025, is the kinetic energy from nuclear. Kinetic energy from nuclear is higher in 2025, even when the total installed kinetic energy is the same for both scenarios. One explanation to this is the availability of Olkiluoto 3, that in 2020 is assumed to be lower compared to 2025.

The simulation results indicate that low-inertia situations (below 120 GWs) will occur in the 2020 and 2025 Nordic power system; the number of hours where this occurs, seems to be limited though. This limited number of low-inertia hours does not provide a sound basis for introducing a market for mitigation measures.

For the simulations in this report, a one-machine equivalent of the power system has been developed. In order to make the simulation model represent the current power system, a tuning of the model parameters has been performed, where the simulated frequency from the model is tuned to the measured frequency in the real power system. The model, with the best model parameter set, has been validated by using other disturbance data.

Various mitigation measures of low-inertia situations are proposed and – by means of the simulation model – tested on their efficiency. An overview is provided in Figure 10-2.

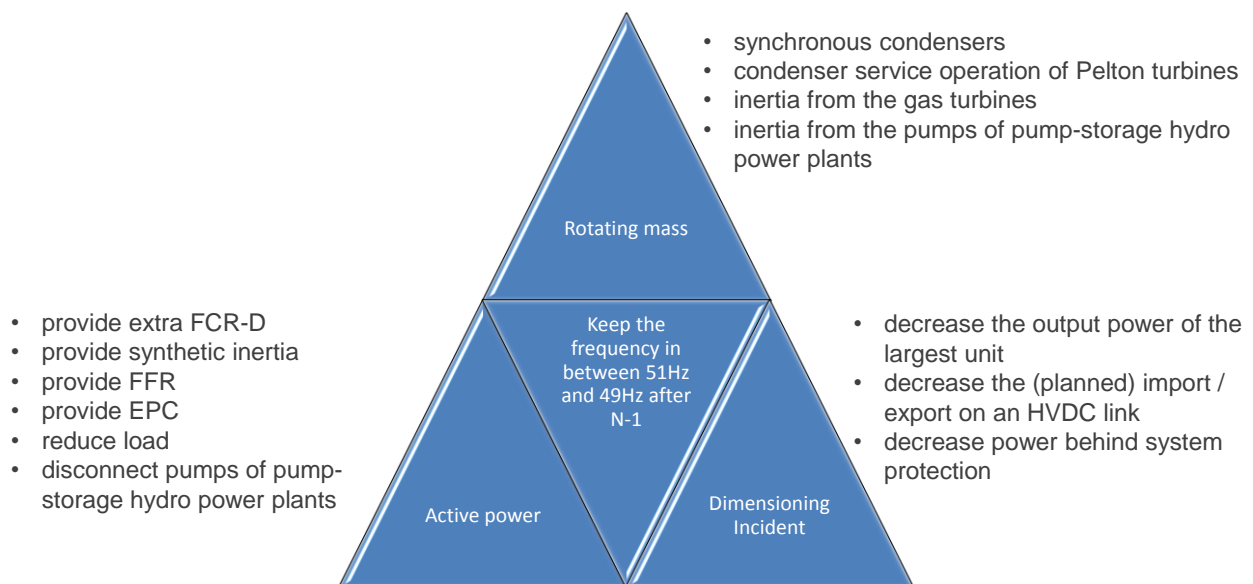


FIGURE 10-2 LOW-INERTIA MITIGATION MEASURES

The different mitigation measures have been evaluated on the basis of a Multi-Criteria Assessment (MCA). In an MCA, the different mitigation measures are scored on the basis of criteria, such in order to get a grip on the most promising ones. In this case the focus is on the most promising mitigation measures to be applied in 2020.

The reduction of the dimensioning incident, a measure already existing today, scores low in terms of cost and can be seen as a “plan B”. The “plan A” mitigation measures – being most promising in terms of potential, effectiveness, being sufficient, and cost that can be available in 2020 – consist of active power injections. The active power injection can be realized by:

- EPC; a redesign of the EPC settings has been proposed to make it a more efficient mitigation measure,
- Load disconnection, and
- Disconnection of pumps for hydro storage (being a special case of the load disconnection).

Both synthetic inertia and fast-frequency reserve are defined in the report, as follows:

Synthetic inertia is defined as the controlled contribution of electrical torque from a unit that is proportional to the rate of change of frequency measured at the terminals of the unit [12].

Fast-Frequency Reserve (FFR) is a system service that delivers a fast power change to mitigate the effect of reduced inertial response, so that frequency stability can be maintained.

As such, both the EPC and load disconnection can be seen as FFR products.

In order to have a real-time grip on the inertia in the system, all Nordic TSOs have implemented a kinetic energy estimation ($E_{k,sys}$) in their SCADA/EMS, whereas the online dimensioning incident determination (ΔP) has been implemented in the SCADA systems as well, within the framework of this project. With these online data available, the following linear regression model has been implemented in the Finnish SCADA system (and shared with the other Nordic SCADA systems), for an online $f_{extreme}$ estimation, in case of a dimensioning incident in the system:

$$\Delta f_{\text{under-frequency}} = 0.07570 \cdot \frac{\Delta P}{E_{k,sys}} - 0.03690 \quad (10.1)$$

$$\Delta f_{\text{over-frequency}} = 0.07041 \cdot \frac{\Delta P}{E_{k,sys}} + 0.04463 \quad (10.2)$$

where ΔP is provided in MW (being a positive value for over-frequency and a negative value for under-frequency situations), and the $E_{k,sys}$ is in GWs. The linear regression analysis has been performed in order to find the best fit of the model with the disturbance data in a roughly one-year period (from 2015-07-20 to 2016-09-28), consisting of 19 under-frequency, and 26 over-frequency cases. The interaction of the model and the SCADA system has been implemented in such a way that more advanced models may be implemented in the future, such as the one-machine equivalent of the power system, that has been developed for offline studies within this project.

10.2 FUTURE WORK

Follow-up work of the Future System Inertia 2 project is suggested to consist of two pillars: an implementation project and a research project.

Implementation project:

- Implement the quick wins in terms of Inertia mitigation measures (being the EPC, and load disconnection), in order to have measures at hand in 2020
- SCADA implementation continuation, including amongst others the use of the real-time situation of the EPC available in the $f_{extreme}$ computation
- Inertia forecast implementation: assess the expected kinetic energy in the system based on CGMs (Y-1, M-1, W-1, D-2, D-1, and ID)

Research project:

- Towards a more dynamic assessment of Frequency Containment Reserves for Disturbances (FCR-D) and inertia needs

- Link to the Frequency Quality 2 (FQ2) project: inertia required to meet the quality criteria
- Link to the Revision of the Frequency Containment Process (FCP) project: coordination between fast-frequency reserves (FFR) and FCR-D (not separate them): be able to relax one at the expense of the other
- Practicalities: what is feasible, and what is the most promising technology for delivering FFR services
- Product definition and FFR requirements: e.g. proportional (closed loop) or pre-determined (power boost) power injection
- Develop a view beyond the quick wins ('target solution')
- Online situational awareness of the frequency stability (the 'big picture')
- Investigate / assess how much inertia is coming from the loads
- Continue the cooperation with other synchronous areas

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Appendix A QUESTIONNAIRE

INFORMATION ABOUT YOU AND YOUR COMPANY

Name:

Email:

Department:

Company:

GENERAL INFORMATION ABOUT YOUR SYNCHRONOUS AREA

1. Please describe your synchronous area, by name, geographical extent, and the Transmission System Operators or Independent System Operators involved.
2. Is your system a centralized dispatch / production planning system, or a market-driven dispatch / production planning system?
3. Is low inertia an issue in your synchronous area? If so, please describe what this issue is.
4. What inertia, measured by kinetic energy (GWs), do you observe today in your synchronous area (e.g. over the last year)?
 - a. Minimum inertia:
 - b. Average inertia:
 - c. Maximum inertia:
5. What is the load (GW) in your system (e.g. over the last year)?
 - a. Maximum load:
 - b. Minimum load:
6. What is the size of the dimensioning Incidents²² (MW) in your synchronous area?
7. What is the share of generation (% of installed capacity) that does not contribute to the inertia in your synchronous area (e.g. in the last year)?
8. How much DC interconnection capacity to other synchronous areas do you have installed (MW)?

²² Dimensioning Incidents means the highest expected instantaneously occurring Active Power Imbalance in both positive and negative direction.

9. With regard to primary reserves,
 - a. What is the volume (MW) available?
 - b. What is the activation time?

INERTIA ASSESSMENT

10. With regard to the current inertia assessment in your synchronous system,
 - a. Do you assess the current inertia in your system?
 - b. Do you have an on-line inertia estimation system in place?
 - c. If so, can you elaborate how this system functions?
 - d. If you have an online inertia assessment in place, can you please indicate how these real-time inertia values are used?
11. With regard to the future inertia assessment,
 - a. Have you assessed the expected inertia in the future?
 - b. If so, can you please elaborate on the methodology applied, the time horizons (next week, next year, 2020, 2025, ...), assumptions made, the findings of your assessment and the potential follow-up actions triggered by it?
 - c. If not, can you please indicate if there are plans to do so, and how you foresee performing these assessments?
12. If you compare the current inertia with the forecasted inertia in the future, and there is a change, what are the key factors driving this change?

MITIGATION OF LOW-INERTIA SITUATIONS

13. What do you do to deal with low-inertia situations:
 - a. Today?
 - b. In the near future (2017–2020)?
 - c. Further into the future (2020–2025)?
 - d. In the far future (2025–)?
14. Are your solutions for dealing with low-inertia situations market-based or a non-market based?
15. Is there a requirement for inertia in the grid code(s) in your system?
16. Do you have synthetic inertia, fast-acting reserves, or something else in place to support the low-inertia situations?
17. If you have synthetic inertia or fast acting reserves, are they provided by HVDC, production connected via power-electronic converters, or other techniques? Which?

ZOOMING IN ON THE FREQUENCY

18. Please provide the normal frequency range (Hz) for system operations in your synchronous area.
19. In your synchronous area, at an under-frequency, what is the frequency (Hz) or RoCoF (Rate of Change of Frequency, Hz/s), when load shedding starts?
20. In your synchronous area, at an over-frequency, what is the frequency (Hz) or RoCoF (Hz/s), when generation curtailing starts?
21. Please provide a graph of the frequency after a disturbance if you have such (e.g. 0–60 seconds). Please elaborate on the disturbance (size of the disturbance, and the system circumstances, such as load level and kinetic energy).
22. If available, please provide a graph with the variation of the kinetic energy over a year.

Appendix B DISCONNECTION OF ELECTRICAL BOILERS AND HEAT PUMPS IN SWEDEN

In the Nordic system operation agreement²³ load shedding is specified. In Sweden loads, in the form of electrical boilers and heat pumps, are required to disconnect depending on their rated power, see Table B-1.

TABLE B-1 AUTOMATIC LOAD SHEDDING OF ELECTRICAL BOILERS AND HEAT PUMPS IN SWEDEN

| Rated power | Frequency trip level [Hz] | Time delay [s] |
|---------------------|---------------------------|----------------|
| $P \geq 35$ MW | 49.4 | 0.15 |
| $25 \leq P < 35$ MW | 49.3 | 0.15 |
| $15 \leq P < 25$ MW | 49.2 | 0.15 |
| $5 \leq P < 15$ MW | 49.1 | 0.15 |

During operation the volume of connected load is unknown to the TSOs. To get better knowledge, the project asked distribution companies for time series data of the connected boilers and heat pumps. Vattenfall and E.ON supplied data of 17 units with a total rated power of 347.6 MW. This does not represent the total amount of boilers and heat pumps installed in Sweden. The total amount of load with this system protection is unknown. The time period where data was available from all 17 units was during 2016.

The data is divided into the four threshold levels and shown as time series in Figure B-1, and duration curves in Figure B-2.

From the figures it is possible to see that the available load varies a lot in time. The data shows that the available load can sometimes be as low as 0 MW for some of the threshold levels. Since there is no real-time observation of this in the control centre, one cannot expect that there should be any load disconnections while dimensioning the reserves.

²³ Nordic TSOs, "Nordic System Operations Agreement," [Online]. Available: <https://www.entsoe.eu/publications/system-operations-reports/nordic/Pages/default.aspx>. [Accessed October 2017].

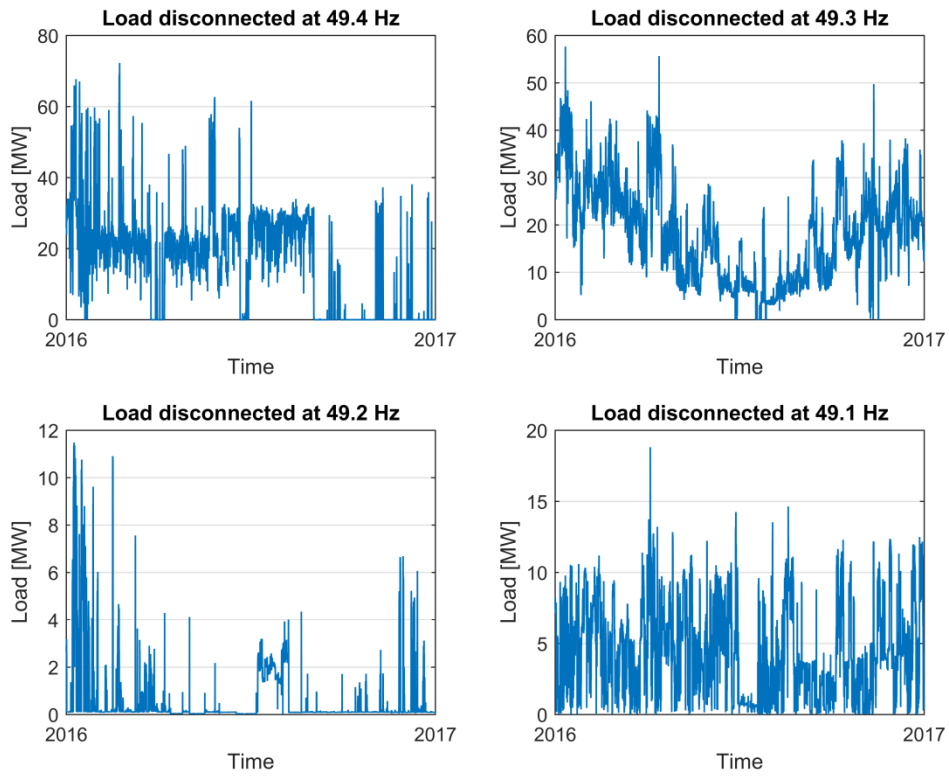


FIGURE B-1 AVAILABLE LOAD DISCONNECTION FROM 17 BOILERS AND HEAT PUMPS CONNECTED TO VATTENFALL AND E.ON

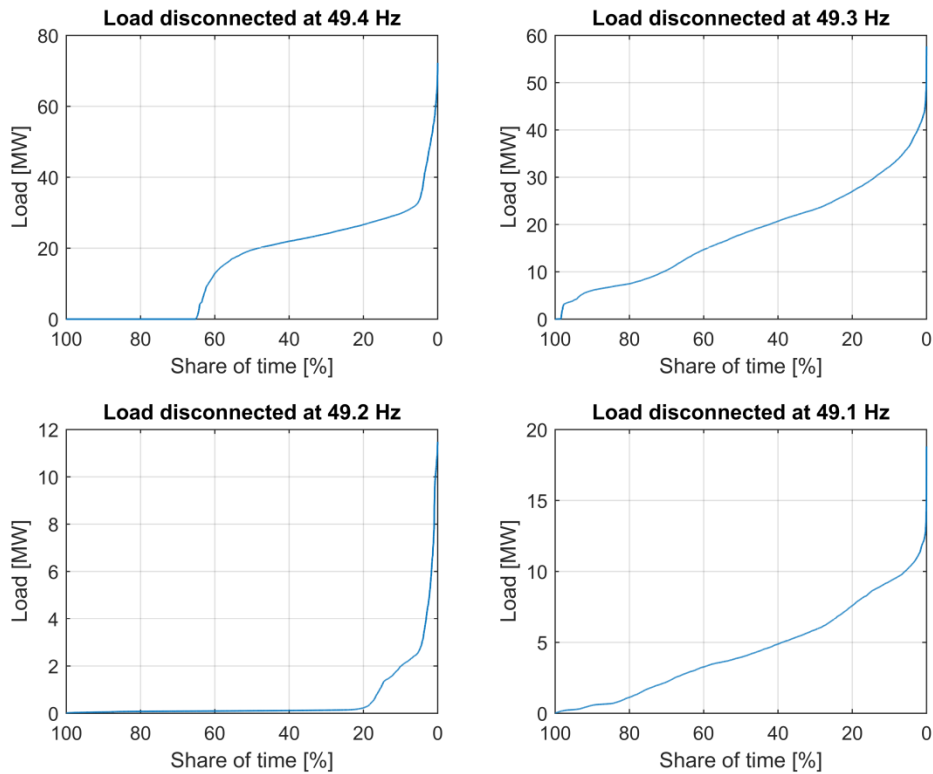


FIGURE B-2 DURATION CURVES OF AVAILABLE LOAD DISCONNECTION FROM 17 BOILERS AND HEAT PUMPS CONNECTED TO VATTENFALL AND E.ON

Appendix C **BRIEF DISCUSSION ON COSTS OF ANCILLARY SERVICES**

Welfare optimization means efficient allocation of resources. Mechanisms for efficient resource allocation balance the socioeconomic costs and the socioeconomic benefits in the long term. Competitive markets do this if the conditions are ideal. But when market imperfections prevent market participants from coordinating on optimal resource allocation, then socioeconomic and procurement and provision costs must be considered in the development of mechanisms for resource allocation. This note argues that design and dimensioning of ancillary services should be done considering the socioeconomic costs, that the procurement costs are not necessarily a good proxy for the socioeconomic costs, and that the socioeconomic impacts of an imperfect resource allocation may be small. Most importantly, this note does not claim to present clear answers, but rather to dissuade a myopic focus of procurement costs in a TSO perspective, and to weaken expectations of efficient resource allocation being ensured by markets.

The discussion is based on illustrations of optimization with non-convex costs. A more formal analysis of markets with non-convexities is found in "Pricing in Non-Convex Electricity Markets"²⁴, and others^{25,26,27}.

The provision of automatic balancing (rotating) reserve is chosen as a case for illustration, but the cost considerations are also relevant for other products and services. Rotating reserves come at two types of costs: The fixed cost of reserve capacity and the variable cost of reserve activation. The focus here is on reserve capacity costs, not the costs of reserve activation. For simplicity, only reserve capacity for upward regulation is considered.

After a brief introduction below, three different perspectives of costs are discussed below before the costs are illustrated by examples of energy and reserve provision from a small and simple production system.

Optimization mechanisms, prices and non-convexity

The generation of electric energy has a direct impact on fuel usage and fuel costs. Reserve requirements have an impact on fuel usage and total costs. The attribution of costs to energy and reserves is hard or impossible, and the definition of energy and reserve prices is unclear. Heuristics are called for.

Consider the following welfare optimization of energy consumption over time, assuming invariant preferences and costs, and no discounting:

²⁴ Araoz, V.: "Pricing in Non-Convex Electricity Markets", PhD thesis at Norwegian School of Economics, Department of Finance and Management Science, 2012.

²⁵ Gomory, R. E. and Baumol, W. J.: "Integer Programming and Pricing", *Econometrica* Vol. 28, No. 3, 1960.

²⁶ Doorman, G. and Nygreen, B.: "Market Price Calculations in Restructured Electricity Markets", *Annals of Operations Research* Vol. 124, 2003.

²⁷ O'Neill, R. P. et al.: "Efficient market-clearing prices in markets with nonconvexities", *European Journal of Operational Research* 164, 2005.

$$V(E(t)) = \max \sum_{t=1}^T (U(E(t)) - C(E(t)))$$

Subject to:

(C.1)

$$R(t) \geq R'$$

... and other constraints

The optimal value V is the objective or "value function" of the welfare optimization, representing the total utility minus total costs of the optimal sequence of energy production and consumption $E(t)$. The marginal utility in each period, $U'(E(t))$, can be seen as the marginal "willingness to pay" ("WTP") or "price" in each period. If production and consumption is flexible in time, the price will be constant. If the demand is inflexible and energy storage and plant capacities are limited, then prices will vary.

If the optimization problem involves convex costs and is well behaved, then it can be solved by linear programming. The price in each period will be equal to the shadow price of a constraint, or the sum of several such constraints. A "shadow price" is the impact on the objective function V of a marginal change of a constraint. This is illustrated below for a situation where the total production capacity is limited. The price is the sum of the shadow price a of plant output, and the shadow price b of the total production capacity. The latter can be understood as the premium on scarcity that is necessary for efficient rationing of consumption.

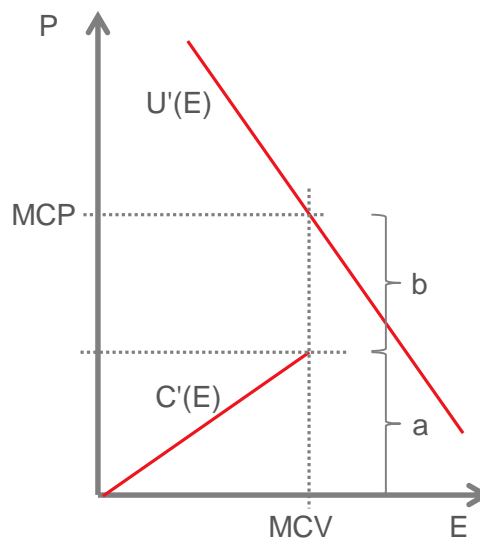


FIGURE C-1 MARKET SITUATION WHERE THE TOTAL PRODUCTION CAPACITY IS LIMITED

The reserve requirement $R(t)$ is the only constraint listed, but not the only one to consider. Other constraints are plant capacity limits, minimum load requirements, acts of nature such as hydrology, wind and sunlight. The real-world consumption is hard to represent credibly by a utility

function, as much of consumption is just forecasted ex-ante, not actively participating in a market, and not metered with the time resolution used in the energy market.

In addition there are parameters to consider, such as fuel prices. Constraints and losses in the transportation of energy are also absent from the model above.

Less behaved optimization problems involve non-convex costs. The "non-convexity" means that feasible allocations cannot always be combined by linear interpolation. As a simple example, consider 100 MW that can be delivered from either of two plants. If both plants have a minimum load of 60 MW, the production volume cannot be delivered by both units running. With the decision on starting a plant or not, respecting the minimum load and considering the efficiency curve, the optimization of $V(E(t))$ becomes a mixed-integer problem (MIP) - a mix between a combinatorial problem and the tuning of the production for a selected combination of running units. This note argues that the combinatorial problem is difficult, but that the social cost (the impact on V) of failing to find the optimal combination may (or may not) be small, at least compared to the distributional impacts. In other words: There may be little to gain for society by improving a near-optimal allocation, but the combinatorial part of the allocation may have significant impact on some market participants (that are either in or out) or all (if the prices are affected).

The optimal allocation of resources can be sought in different ways - by an omniscient and benevolent social planner (or algorithm), or by a market. These are broad categories and deserve further discussion. With well-behaved costs and preferences and ideal circumstances such as price-taking market participants and perfect information including price expectations, then the competitive market delivers the same outcome as the social planner. This is the essence of the First Fundamental Theorem of welfare economics. The Second Theorem states that under certain circumstances, any Pareto optimal resource allocation (such as The Optimum) can be achieved as a market equilibrium. This implies that given a set of prices, the rational market participants will coordinate on the optimal allocation. This does not hold for resource allocation involving non-convex costs, as the "shadow prices" of a MIP optimization do not offer simple economic interpretations. This complicates the design of market mechanisms and the understanding of prices.

The provider's costs

For the provider of automatic balancing reserves, the possible surplus from alternative uses of the capacity constitutes defines the capacity cost, whereas the activation cost is equal to the marginal fuel cost per energy output unit.

The nature of the capacity cost depends on the generating unit being infra-marginal in the energy market, i.e. having a marginal cost below the marginal price of the energy market, or not. For an infra-marginal producer, the provision of rotating reserve means forsaking a profit in the energy market. For a producer having a marginal cost above the energy price, the capacity cost arises from the need to run at or above minimum load, incurring fuel costs that are only partly covered in the energy market.

- Reserve capacity cost for the infra-marginal plant:

- $C(R) = \text{profit (capacity used without restriction in the energy market)}$
 $\quad - \text{profit (capacity used in the energy market after providing reserve R)}$
- Note that the total cost for reserve provision depends on the amount of reserve provided.
 - Reserve capacity cost for the extra-marginal plant:
 $C(R) = 0 - (\text{fuel costs for running at minimum load or above}) + (\text{revenue in the energy market})$
 - Note that "0" is the profit in the energy market if the plant is idle. Also, note that the total cost for reserve provision does not depend on the amount of reserve provided, within the limitations of the plant.

In order to describe the costs further, consider the illustration of an efficiency curve below. The plant output level and efficiency are given as percentage values. The efficiency curve is shown as a conveniently linear line starting at minimum load and ending at the maximum output level. Note that the linear shape and the "best point" of maximum efficiency at the maximum output are convenient for illustration, but not general properties of generation plants.

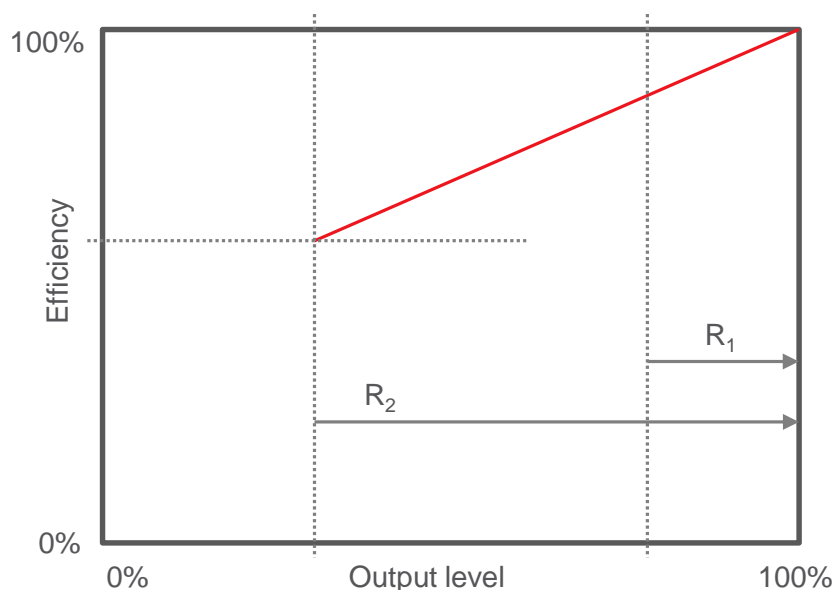


FIGURE C-2 EFFICIENCY CURVE

Introducing some variables, the reserve costs can be expressed more clearly:

- CAP is the plant capacity
- ML is the minimum load
- FC is the fuel cost per energy output at maximum efficiency, i.e. maximum load in this example
- $C(R)$ is the capacity cost for provision of reserve R.
- $x = \text{CAP} - R$ is the output level

- $\eta(x)$ is the efficiency at the output level x of the plant, and $FC/\eta(x)$ is the corresponding energy unit cost.
- P_E is the energy (spot) price.
- $TC(x)$ is the total energy cost $x*FC/\eta(x)$

For the infra-marginal plant, considering $R = R_1$ in the illustration:

$$\begin{aligned} C(R) &= (P_E - FC) * CAP - (P_E - FC/\eta(CAP-R)) * (CAP-R) \\ &= (P_E - FC) * R + FC * (1/\eta(CAP-R)) * (CAP-R) \end{aligned}$$

The first expression subtracts the energy market profit with reserve provision from the profit without reserve provision, illustrated below as the area of the whole rectangle minus the area of the dotted upper left rectangle. The second expression takes the lost profit from the reduced energy volume and adds the increased fuel cost due to running at a reduced efficiency. This corresponds to the areas of the two shaded rectangles in the illustration below.

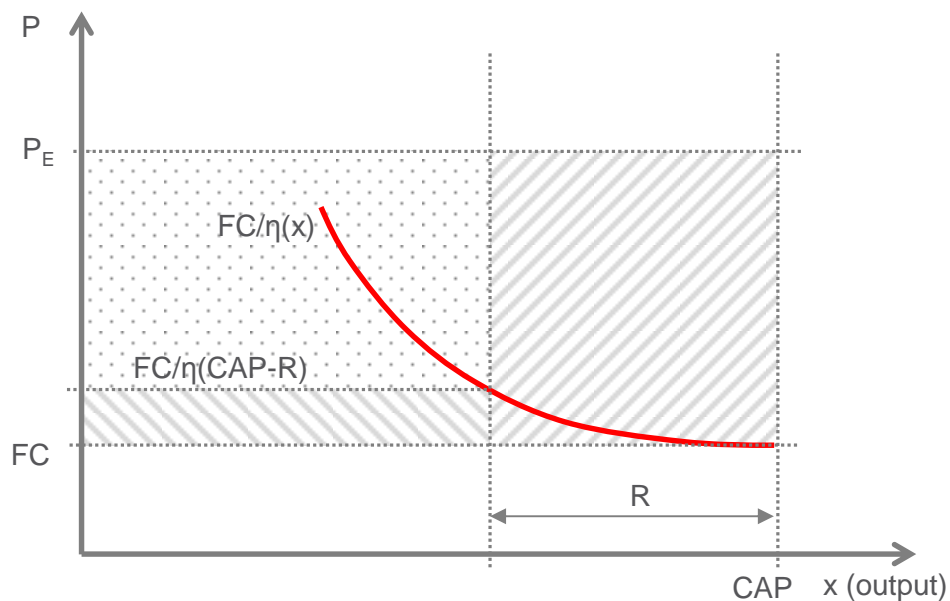


FIGURE C-3 ILLUSTRATION OF THE CAPACITY COST FOR PROVISION OF RESERVES

The reserve activation cost deserves a brief note: due to the increasing efficiency at a level $x < CAP$, the marginal energy cost $dTC(x)/dx$ is lower than FC . Near-zero and even negative energy costs are possible.

For the extra-marginal plant, i.e. a plant having marginal cost higher than the energy price, the reserve capacity cost corresponds to producing energy at a loss at or above minimum load. Considering $R = R_2$ in the first illustration above, the provider's cost is:

$$C(R) = [FC/\eta(x)] * x$$

Where the energy output $x \geq ML$ and $R \leq (CAP-x)$

Note that $C(R)$ is independent of R , and the startup cost is the only cost for any R in $[0, (CAP - x)]$.

Procurement costs of reserves

For the analysis of procurement costs, prices are necessary. If "market prices" can be deduced from a model, then these prices are multiplied by the procurement volume to give the procurement costs. An alternative way of compensation is PAB, i.e. "pay-as-bid". The market prices are hard or impossible to derive from a non-convex model, and heuristics must be developed for this purpose. Some desirable properties²⁸ of market prices are:

- They allow market participants to cover their costs
- They incentivize bid prices based on market participant costs
- They serve as information for market participants to coordinate on an efficient allocation of resources
- They represent a Nash equilibrium, meaning that no market participants would change his portfolio given the actual prices

Some of these are harder to achieve than others, and there is some overlap between the listed properties.

If PAB is used for compensation of balancing reserves, then two observations should be made:

- There is limited incentive for market participants to price their bids based on their real costs (based on estimated energy prices). There is a balance between a mark-up on the costs and the competition for market volume, and competition that may be stronger when balancing reserves are exchanged between TSOs. There is a potential for collusion where market participants coordinate on a high price estimate.
- Assuming that market participants price their bids based on their costs, a dubious assumption maybe, there is no producer surplus in the market, and the total procurement costs based on PAB are equal to the total socioeconomic costs of reserve provision. This does not hold on the margin, beware – illustrations will follow below.

Socioeconomic costs of reserve provision

The costs of reserve capacity provision can be studied by varying the requirement R' and observing the impact on the value function V . Consider a case with only one period, and an energy market clearing at a volume and a price that maximize the social welfare, balancing marginal costs and willingness to pay. If no rotating reserve is required and plants are many and small, then the running capacity will be equal to the quantity set by the energy market as shown in the figure below. However, if plants are lumpy, some spare capacity may running, typically at the plants that have marginal costs near the market price. If plants are lumpy and reserve requirements are introduced, then more running capacity may be needed. Depending on the slope of the energy market supply curve, and the minimum load of extra-marginal plants, the optimal allocation of reserve capacity, i.e. the allocation that maximizes V , falls on both sides of the energy market

²⁸ Expressed from a practical view and not a mathematical one – "separating hyperplanes" are kept out of this note.

clearing. Further, the market clearing itself may be hard to determine without some heuristics, or as in the case of the day-ahead market, the stochastic outcome of a discrete optimization that delivers the best result found within the time given for the market algorithm.

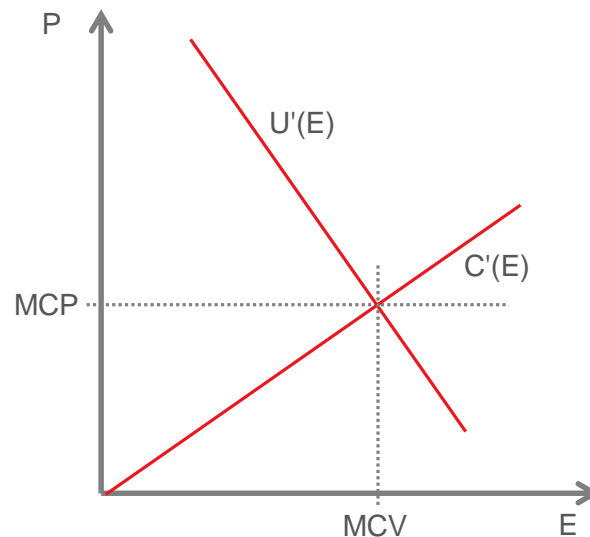


FIGURE C-4 MARKET CLEARING

The following examples discuss the optimal provision of energy and reserves in order to cast some light on the social costs of reserve capacity. First, the difficulties in finding prices in an optimization with lumpy (indivisible) plants is illustrated. The socioeconomic costs are shown by comparing fuel costs of different examples, and finally the socioeconomic costs and costs of reserve capacity procurement are compared.

Example 1: Production model and energy optimization

Consider a production model of plants u_1 – u_{10} as shown below. Some plants are chosen to be big and to use cheap fuel, and others are smaller and use fuel that is more expensive. The minimum load is set to 50 % of capacity for all plants except the two smallest, running from 20 % of capacity. The efficiency at minimum load is 60 % for all plants, and 100 % by default at maximum output. The efficiency increases linearly between minimum and maximum load. The energy unit cost and marginal cost at different output levels are shown in separate diagrams. Note that the marginal energy costs are well below the unit costs.

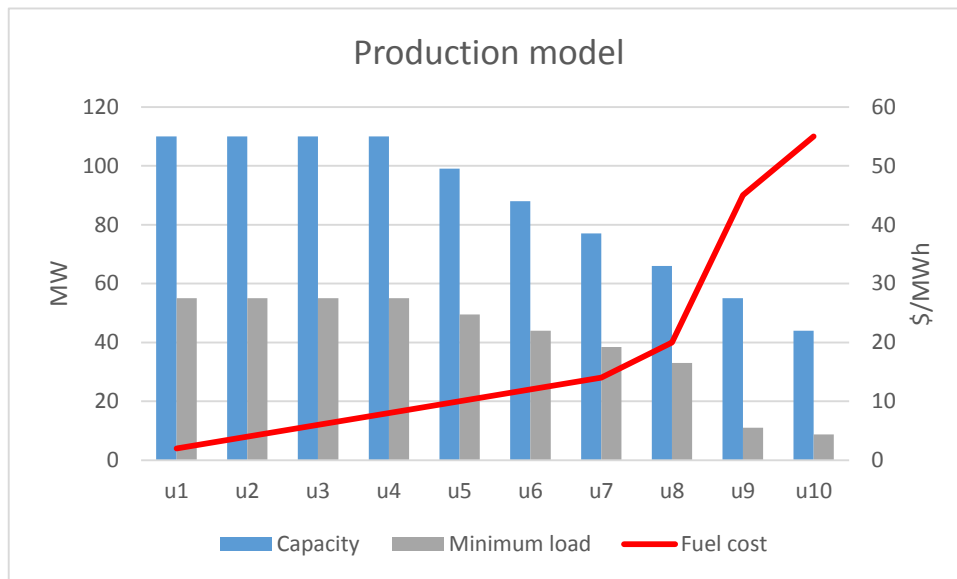


FIGURE C-5 PRODUCTION MODEL

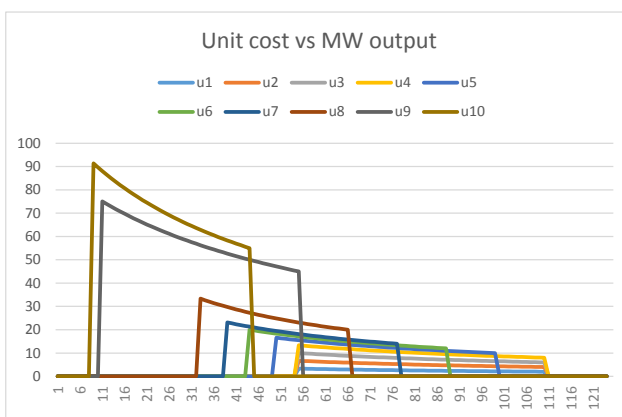


FIGURE C-6 UNIT COST VS MW OUTPUT

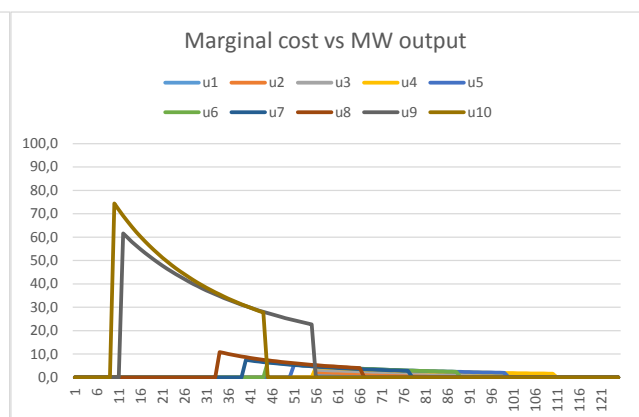


FIGURE C-7 MARGINAL COST VS MW OUTPUT

For the optimal production of energy, the plants are dispatched in merit order, and the marginal unit operates on partial load and at an efficiency lower than 1. The optimal allocation is illustrated below for a total output of 700 MWh/h. Simple as it may seem, this outcome is not a Nash Equilibrium. Taking the marginal cost (14.6 \$/MWh) as a market clearing price, the marginal unit u7 would prefer to run at maximum load and lower unit cost, thereby earning a positive surplus. Thus, even before introducing reserve requirements, the "price" is a less-than-perfect concept.

Note that the available reserve after the optimization of energy is 4 MW.

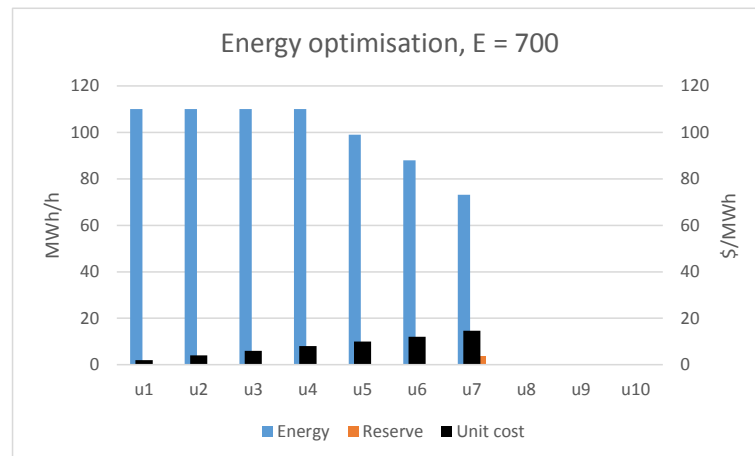


FIGURE C-8 OPTIMAL ALLOCATION FOR A TOTAL OUTPUT OF 700 MWH/H

Example 2: Optimization of energy and reserves

We introduce a higher reserve requirement, say, 40 MW. Another unit must be started, and there are three candidates, u8, u9 and u10. A possible optimum is illustrated below. The output of the marginal unit in the energy optimization is reduced, and the smallest unit, u10, is started. Other feasible allocations may use u8 or u9 instead of u10, but those seem to increase the total cost, thus reducing the objective function $V(E(t))$.

The combination of units is one of a finite set of discrete options. With many units, the number of possibilities becomes large, and finding the optimal combination requires time and proper algorithms. In practice these resources are insufficient, for example in the energy spot market where "good enough" solutions are delivered. In this example of 10 units, some of them seemingly unaffected ("base load"), optimal combinations should be easily found. Nevertheless, optimal combinations are merely suggested in the following, and may be wrong.

The available reserve after the optimization is 48 MW, i.e. a surplus delivery of 8 MW.

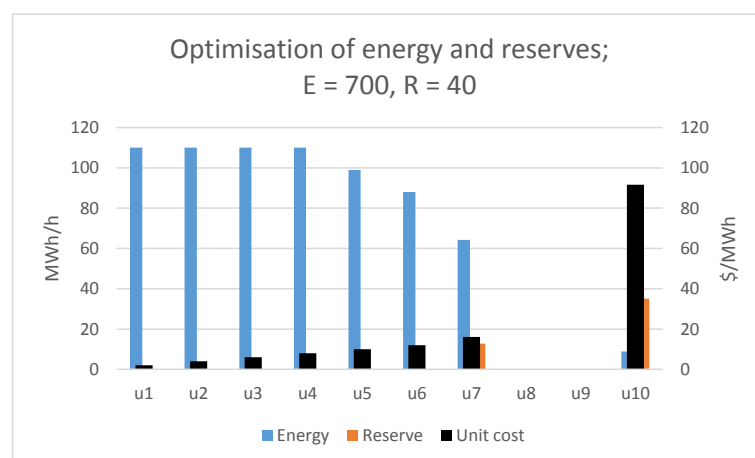


FIGURE C-9 OPTIMAL ALLOCATION FOR A TOTAL OUTPUT OF 700 MWH/H, AND A RESERVE REQUIREMENT OF 40 MW

How can the prices of energy and reserve be found, or invented? Heuristics are necessary for both, which means that there is no "right" answer, just an assessment of pros and cons. The marginal

cost corresponds to the most expensive unit running at minimum load and lowest efficiency. The unit cost is 91.6 \$/MWh (= 55/0.6), and clearly a bad signal for the energy market. All plants would prefer to run at maximum load. One rule for the energy market price could be to take the highest unit cost of any plant that runs above minimum load, leaving the necessary cost coverage of the plants at minimum load for the reserve payment. That suggests an energy price of 16.1 \$/MWh.

The next question is the pricing of reserve capacity. At least two strategies are possible: Marginal price, and pay-as-bid. The first option is dubious. The optimization of energy and reserve provision per plant would result in a surplus of both products. To see this, observe that the smallest unit delivers 9 MWh at unit cost of 96.6 \$, and is paid a price of 16.1 \$ for the energy. It needs to recover 679 \$ in the reserve market. It delivers 35 MW of reserve, and a marginal price would be 19.3 \$/MW. At this combination of energy and reserve prices, the units u8 and u9 would also prefer to run at minimum load or more to maximize the surplus. So the marginal price creates more trouble for the Nash equilibrium. Another problem is that the procurement costs of the reserves would be inflated, thereby causing a redistribution of resources that might be hard to justify.

The pay-as-bid option is better than its reputation in this case, as it does not worsen the incentive problems of the prices in the energy optimization. Also, the surplus of reserves has no impact on the payment. A challenge with the pay-as-bid option is that it does not give the market participants strong reasons to bid their real costs. There is a risk that prices collude at a high level, thereby causing redistribution again, and a less-than-optimal allocation of resources, essentially of electric energy and fuel. This note argues that the inefficient allocation may (or may not) come at a small cost. The risk of strategic pricing of bids under pay-as-bid could be mitigated by market surveillance, as the behaviour in the energy market would expose the alternative costs for each plant. Additionally, some rule could require pricing of reserve capacity to be based on costs, or the wholesale electricity market could be implemented with central dispatch based on detailed cost information per plant, and an IT system for security controlled unit dispatch (SCUC). This is not further discussed in this note.

With the heuristics discussed above, what desirable properties are offered by the "prices"? Unfortunately, they do not clear the markets, nor do they offer much support for the market participants to coordinate on an optimal allocation of resources. And they do not guarantee that the market participants base the reserve capacity bids on the alternative costs. But two important functions are still intact: The market participants have an incentive to bid their costs in the energy market, even more so in a market with thousands of units and less obvious convexity problems, and they get their costs covered.

A final observation on redistribution among the plants: The profit of a plant that delivers energy and no reserve increases due to the higher energy price. The marginal unit in the energy market and the unit running at minimum load both cover their costs but earn no profit. Energy and reserves were bought in sequential markets, with the reserve procurement done prior to the energy procurement, the alternative costs of capacity could only be estimated. The uncertainty would be reflected in the pricing of reserve capacity bids and even make a profit possible. The market outcome would differ from that of the social planner, at least in the exact level of the prices, and possibly also in the combination of plants running.

Example 3: Optimization of energy and more reserves

For a reserve requirement of 50 MW another combination of plant must be running. The diagram below could represent an optimal combination. The plant u10 is replaced by u9. The energy price is set by u7 at 16.6 \$/MWh, slightly up due to reduced output and lower efficiency. The energy price of u9 is 74.9 \$/MWh, and the missing money in the energy market must be covered by a payment in the reserves market for this unit. The available reserve after the optimization is 59 MW, i.e. a surplus delivery of 9 MW.

The redistribution among the plants is similar as in the previous example. The impact on the energy price is felt by the plants delivering energy only, and reshuffling of running units has no impact on the units being stopped or started.

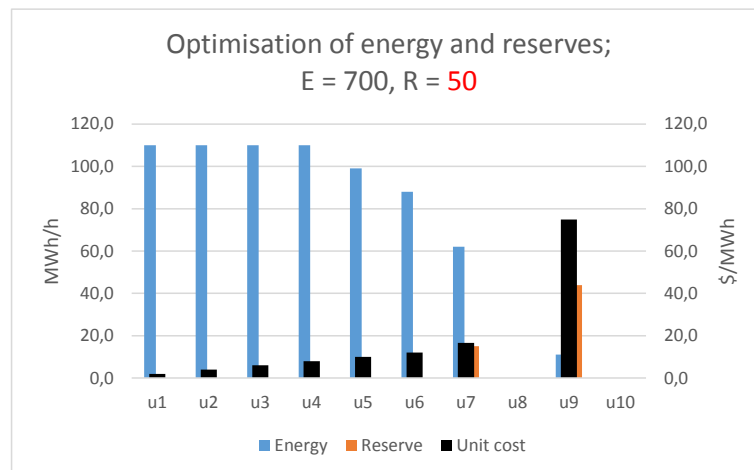


FIGURE C-10 OPTIMAL ALLOCATION FOR A TOTAL OUTPUT OF 700 MWh/H, AND A RESERVE REQUIREMENT OF 50 MW

An alternative to the optimal combination is shown in the next diagram, replacing u8 with u7, and reducing the energy price to 12 \$/MWh, set by u6. This outcome represents a slightly higher total cost, and a very different distribution of welfare due to the lower energy price.

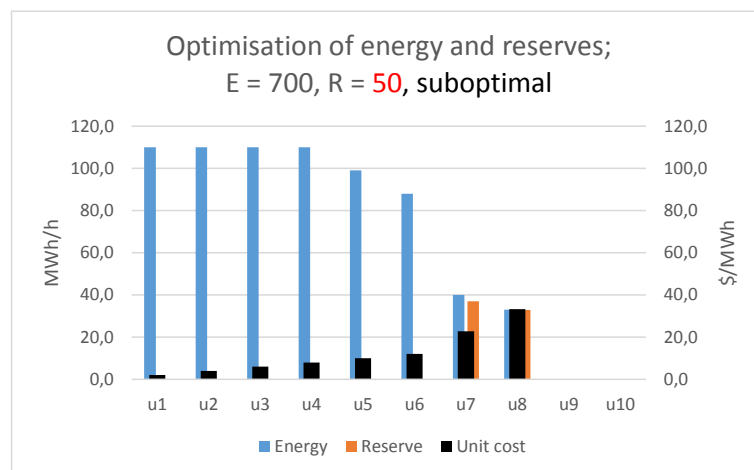


FIGURE C-11 ALTERNATIVE OPTIMAL ALLOCATION

Example 4: Optimization of energy and even more reserves

For a reserve requirement of 60 MW another combination of plant must be running. The diagram below could represent an optimal combination. The plant u9 is replaced by plants u7 and u8, both running at minimum load. The energy price is set by u6 at 12 \$/MWh, i.e. lower than all of the examples above. The highest energy unit cost, of u8, is down to 33.3 \$/MWh, whereas u7 delivers energy at a cost of 22.7 \$/MWh. As all units are running on either minimum or maximum output, a quite peculiar case, this outcome would be an unlikely result of sequential product markets. The plant u7 could end up with a higher energy volume and thereby setting the energy price above 20 \$/MWh (The redistribution impact is capricious and strong. An even more peculiar case would be u7 having the same owner as one or more of the base load plants, and an understanding of the frequency of u7 being on the brink of the combined energy and reserves market).

This example differs from the previous ones in the possibility of significant redistribution of profits, due to the impact on the reserves on the energy price. However, the price impact should be smaller, possibly negligible, in an energy market consisting of many small producers.

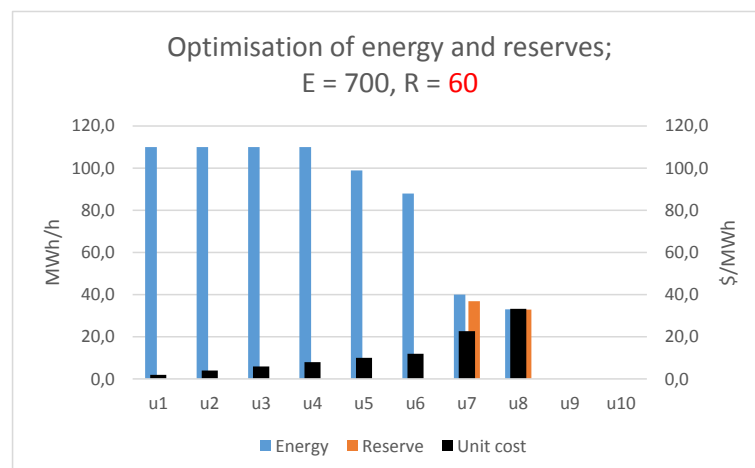


FIGURE C-12 OPTIMAL ALLOCATION FOR A TOTAL OUTPUT OF 700 MWH/H, AND A RESERVE REQUIREMENT OF 60 MW

An alternative to the optimal combination is shown in the next diagram, replacing u8 with u9 and u10, and increasing the energy price to 18.6 \$/MWh, set by u7. This outcome represents a significantly higher cost, but would be a more likely outcome if the optimization were left for market mechanisms to deliver.

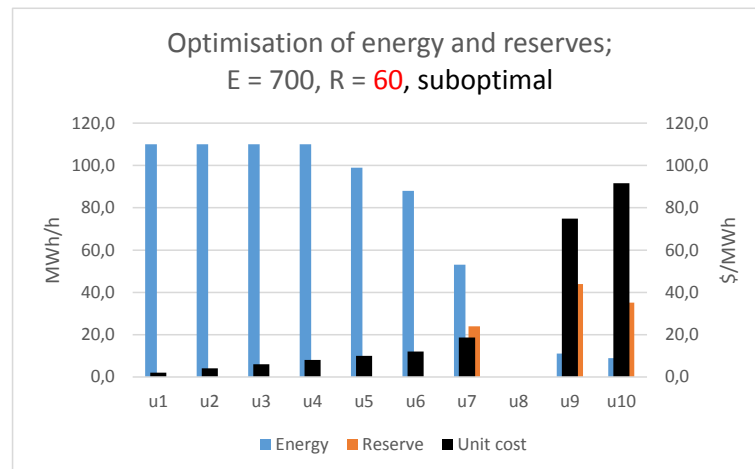


FIGURE C-13 ALTERNATIVE OPTIMAL ALLOCATION

Examples summarized: Social costs, procurement costs and redistribution

The diagram below compares the costs and redistributive impacts of providing the chosen energy volume together with different volumes of rotating reserves. An increased reserve requirement is a tightened restriction of the feasible domain of the decision variables, and the optimal value of the objective function can at best remain unchanged. This is confirmed by the increase in total (fuel) costs. The social costs of reserves are simply the differences in total costs compared to the level corresponding to no reserve requirement, and the pattern is identical to that of the total cost.

The "PAB cost" is a proxy for the reserve procurement cost, assuming that reserve providers bid their real alternative costs based on accurate estimates of the energy prices. The level of magnitude is near that of the social costs, which makes sense considering that the PAB compensation reduces or eliminates the profits.

The correspondence between procurement/PAB costs and socioeconomic costs weakens when considering that the alternative costs of the providers are based on estimated energy prices. The mutual impact of reserve requirements and marginal energy prices (even after heuristics as described above) cannot be disregarded in times of very high or very low utilization of the flexible production capacity. Also, and the combinatorial impacts on energy prices of near-optimal allocations can have a bigger impact on procurement cost than on social costs.

For the reserve requirements 40 MW and 50 MW and the energy prices determined as argued in the preceding examples, the reserve procurement costs are lower than the corresponding social costs. Note that the marginal PAB costs are not at all well-behaved, decreasing when the reserve requirement is raised from 40 MW to 50 MW. The quantities, 40, 50 and 60 MW are procured at 17, 13 and 19 \$/MW, respectively.

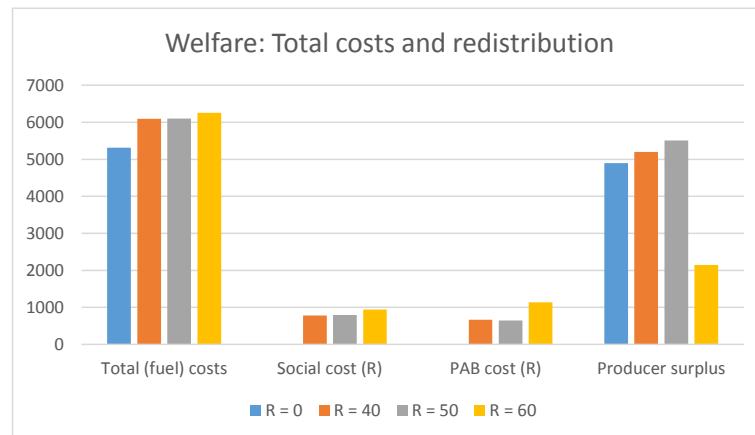


FIGURE C-14 COMPARISON OF COSTS AND REDISTRIBUTION

The total producer surplus (PS) consists of all revenue from the energy market and the PAB compensation of reserves, minus fuel costs. The PS increases steadily when reserve requirements causes the energy price to increase. In the last example, the PS drops due to the lower energy price. Also, the reserve requirement increases the procurement (PAB) cost due to the "missing money" for reserve providers being tied to the energy price, but this higher procurement cost is a smaller impact than the reduced profit of the energy market participants. The increase in social cost is notably smaller than that of the procurement cost.

Before closing the discussion on the welfare impacts of reserve requirements, the diagram below includes the two suboptimal examples in the comparison. The level of magnitude of social costs and procurement costs is still the same, but the monotonicity of social costs is disturbed, and there are capricious changes in producer surplus, with distribution impacts bigger than the differences in social costs.

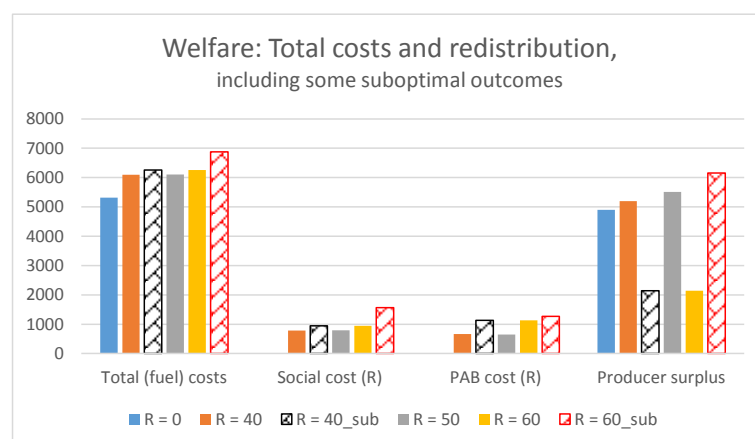


FIGURE C-15 COMPARISON OF COSTS AND REDISTRIBUTION, INCLUDING SUB-OPTIMAL OUTCOMES

The procurement costs may be badly represented by PAB compensation of alternative costs per plant, but at least they serve as a lower bound for the estimated procurement costs. An exaggerated opposite could be the highest alternative cost multiplied by the procurement volume.

In this small and lumpy model, this distorts the observations, but in a model of higher granularity it might offer credible results. The reserve procurement costs would be higher, and as already mentioned, the outcome would not be a Nash equilibrium and the modelling therefore subject to the heuristics of "the visible hand" of the social planner that cannot leave the market all on its own.

Concluding remarks

Social costs and procurement costs of reserves have been shown to differ in the examples, especially on the margin, and less in the order of magnitude. The correspondence between social costs and procurement costs of reserves is reasonable when PAB is used as a proxy for procurement costs, leaving the providers with no profit. No predictable relation is observed between marginal social and procurement costs.

Total distributional impacts, i.e. producer surplus and reserve procurement costs observed together, vary more than the social costs of reserve procurement, in a quite unpredictable manner. This hints that the procurement cost is no reliable representation of the social costs, especially on the margin.

The examples are far too simple and lumpy to emulate real market behaviour and cost impacts, but they do serve to illustrate that the optimization of two products from a production system with non-convexities is hard to achieve with "prices" as instruments of coordination, leave alone finding "marginal prices" and Nash equilibria. The optimal resource allocation would be much harder to find in a big system, but the cost impacts of picking suboptimal allocations would be relatively smaller. This may also apply to the social costs of suboptimal reserve provision. A bigger model might serve to clarify or illustrate this.

For a bigger model, one approach could be to assume that reserve provision has little impact on energy prices, do a combined optimization of energy and reserves to establish an (or "the") energy price, then establish alternative costs for reserves per provider. Finally, the reserve provision could be determined and the energy optimization rerun given the selected reserve providers. This could cast some light on the viability of heuristics for a "market price" of reserves, incentives to price reserves based on costs, and a better comparison of procurement costs and socioeconomic costs. Separate analysis would be necessary for situations of very high or very low utilization of flexible production capacity.

Alternatively, energy market design could be based on central dispatch and detailed data on production costs. This would not eliminate the non-convexities, but it could facilitate near-optimal resource allocation and PAB compensation for ancillary services.