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# Challenges and Opportunities for the Nordic Power System

# Executive summary

This report summarises the shared view of the four Nordic Transmission System Operators (TSOs) Svenska kraftnät, Statnett, Fingrid and Energinet.dk, of the key challenges and opportunities affecting the Nordic power system in the period leading up to 2025.

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:

- The closure of thermal power plants.
- The share of wind power in the Nordic power system is rising. Installed capacity for wind power is expected to triple in the period 2010–2025.
- Swedish nuclear power plants will be decommissioned earlier than initially planned (four reactors with a total capacity of 2,900 MW will be decommissioned by 2020) while Finland will construct new nuclear capacity (one unit of 1,600 MW, which will be onstream in 2018 and another unit of 1,200 MW planned for 2024).
- The capacity from interconnectors between the Nordic power system and other systems will increase by more than 50 per cent in 2025. The existing interconnectors and those under construction are shown in Figure 1.

**Overview of existing HVDC interconnectors and HVDC interconnectors under construction**

| Existing | |
|---|---|
| Skagerrak 1–4 | 1600 MW |
| NorNed | 700 MW |
| Konti-Skan 1–2 | 680/740 MW |
| Kontek | 600 MW |
| Baltic Cable | 600 MW |
| SwePol Link | 600 MW |
| Fenno-Skan 1–2 | 1200 MW |
| NordBalt | 700 MW |
| Estlink 1–2 | 1000 MW |
| Vyborg Link | 1400 MW |
| Storebaelt | 600 MW |

| Under Construction | |
|---|---|
| Cobra | 700 MW (2019) |
| Kriegers Flak | 400 MW (2019) |
| Nord Link | 1400 MW (2020) |
| North Sea Link | 1400 MW (2021) |

**Under development**
(not in map, comprehensive list in Appendix 3)

- Viking Link
- DK West – Germany
- North Connect
- Hansa PowerBridge

*Figure 1 Overview of existing and planned HVDC interconnectors in the Nordic power system. Only those planned HVDC interconnectors with a final investment decision are included.*

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These changes present challenges for forecasting, operation and planning of the power system. Further automatisation and digitalisation of the power system could offer new opportunities within system regulation, and enable consumers to play a more active role. Smart meters, energy management systems, automated demand response and microgrids, are key enablers in the restructuring of the Nordic power system. The Nordic TSOs are developing these enablers both at a national and a Nordic level. There will be an increase in the interconnection of markets, big data processing, price- and system-respondent components and more advanced system-balancing. The system will be more complex, more integrated and more automated, and will require new measures from TSOs, regulators and market stakeholders.

Further development of the currect markets is necessary. Low prices and market uncertainties are clouding the investment climate for new generation capacity and adversely affecting the profitability of existing conventional generation. The capacity mechanisms that are being introduced and assessed in various European countries represent a further challenge. The Nordic TSOs wish to improve the current market design to accommodate these changes.

It is important to adopt a holistic perspective and to plan the transmission grid in relation to the market and the response from both generation and consumption. In order to do this efficiently, the TSOs must have a common understanding of how the changes will affect the Nordic power system and how we can respond.

Figure 2 shows the Nordic TSOs' best estimate scenario of the Nordic energy balances in 2025. The main challenges foreseen by the Nordic TSOs in the period leading up to 2025 include:

- Meeting the demand for flexibility.
- Ensuring adequate transmission and generation capacity to guarantee security of supply and to meet the demand of the market.
- Maintaining a good frequency quality and sufficient inertia in the system to ensure operational security.

These challenges, many of which we are already facing, but which will be more prevalent in the years leading up to 2025, are analysed and discussed in further detail below.

## Nordic energy balances 2025

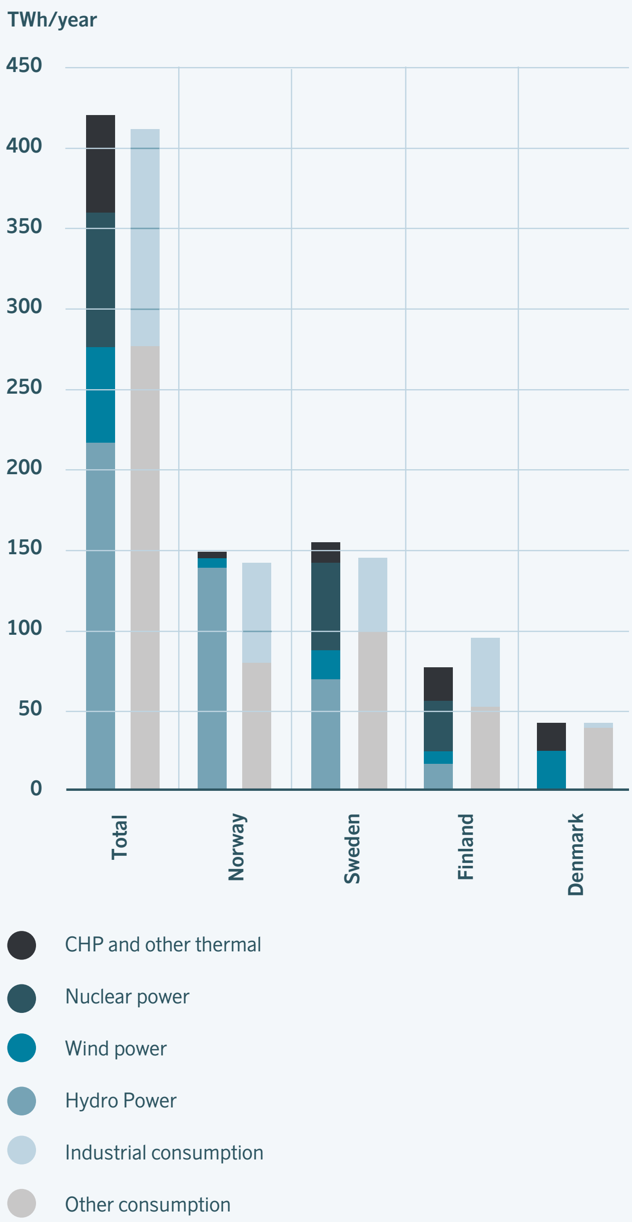


*Figure 2 An estimate of production and consumption in the Nordic power system in 2025 as a result of market simulation in 2015.*

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**System flexibility**

One specific feature of the power system is the need to keep power production at the exact same level as power consumption at all times. This requires flexibility, which can be defined as the controllable part of production and consumption that can be used to change input or output for balancing purposes. Intermittent renewable production is a main driver for increasing flexibility demand, whereas existing flexibility resources are limited and to some extent decreasing. Increased transmission capacity towards Continental Europe can provide flexibility in some situations, but also means increased competition for the low cost flexibility provided by Nordic hydro power.

In a well-functioning power market, a severe shortage of flexibility should be avoidable. However, it is uncertain whether the current economic incentives are sufficiently robust. Potential problems include regulatory and/or technological obstacles preventing a transition to a system with a more diversified supply of flexibility, and market designs intended to secure flexible capacity in line with market signals being developed too late.

Another potential challenge could be distortion of the price signals, for instance through unsuitable RES subsidy schemes or fixed prices for end users. Such market imperfections will present challenges for system operation in the coming years. In severe cases, it could lead to hours without price formation in the day-ahead market, and periods of insufficient available balancing resources in the operational hour. It is also possible that these challenges will occur in individual geographical subareas even though there is enough flexibility available at system-level.

One prioritised area within TSO cooperation involves developing more knowledge about the technological and economical potential for new flexibility, in order to obtain a more accurate picture of prospective challenges in balancing the system. Other possible solutions that could be implemented by the TSOs include:

- Developing markets to provide the needed flexibility. Finer time resolution in the day-ahead and intraday markets as well as the balancing market, and a stronger emphasis on the intraday markets would reduce imbalances and hence the need to balance resources within the operational hour.
- Utilising transmission capacity more efficiently - evaluation of different capacity methods is ongoing.
- Restrict ramping on each HVDC interconnector even further.

Possible solutions requiring broader collaboration:

- Ensuring that the rules and regulations of the market facilitate the most cost-effective development and utilisation of available flexibility.
- Utilising the AMS meters to further develop demand response.

**Generation adequacy**

ENTSO-E's adequacy assessment shows that the Nordic power system will be able to cover demand in the Nordic countries in 2025; however, more accurate assessments will be required to obtain a more reliable evaluation of the situation. The ongoing and predicted changes in the power system will make it more difficult and more expensive to fully eliminate the risk of capacity shortages. This implies a need for a clear definition of generation adequacy, and discussions of the socio-economic best instruments to use in order to maintain generation adequacy.

At the moment, low market prices represent one of the main challenges for the Nordic power system. Reduced profitability of conventional power generation will lead to lower capacity of thermal and nuclear power plants. If price signals do not reach market participants, the latter will not respond by regulating production and/or changing demand in shortage/scarcity situations, or investing in new generation. Thus, securing adequate capacity is also a question of getting prices right.

A second challenge relates to the adoption of appropriate methodologies and definitions. Traditional adequacy methodologies are deterministic and therefore disregard capacity based on intermittent power sources. They also underestimate the value of transmission capacity, and do not cover the stochastic nature of component failure in the power system. In addition, the current adequacy assessments and mitigation measures do not fully value cross-border exchange.

Possible solutions that could be implemented by the TSOs:

- Development of harmonised, shared Nordic probabilistic methodologies to address uncertainties in the power system.
- Measures to address adequacy should be identified from a Nordic perspective; however, mitigation measures can be developed on both a national and a regional level. Hence, the Nordic countries need to identify common principles for mitigation measures.

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Possible solutions requiring broader collaboration:

- Adequacy is to a large extent a common Nordic challenge which will necessitate ongoing common market development and implementation of common adequacy assessments. In order to achieve this, the regulatory framework will have to adopt common definitions of generation adequacy.
- RES subsidies to be coordinated on the regional level.

**Frequency quality**

System frequency is an indicator of the instantaneous power balance between production and consumption and power exchange, while frequency quality is a key indicator of system security. Frequency deviations outside the target area challenge system security by reducing the balancing reserves available to address disturbances. Frequency quality is a common feature of the Nordic synchronous system.

Larger imbalances caused by forecast errors and HVDC ramping present a challenge for the TSOs. Maintaining adequate frequency and balancing reserves is critical for securing real-time balance. The current market design, which is based on hourly resolution, does not guarantee momentary balance within intra-hour timeframes. The trend of increasing intra-hour imbalances is expected to continue as a result of faster, larger and more frequent changes in generation and ramping of HVDC interconnectors. More unpredictable power generation in the Nordic power system will result in more forecast errors.

Another challenge is the increased need for, though reduced access to, reserve capacity in the current market situation. Smaller power plants do not provide the same extent of frequency and balancing reserves as traditional plants. When fewer large power plants are in operation, capacity problems can arise, and the system is less well equipped to maintain stable frequencies.

A third challenge concerns the availability of transmission capacity for frequency and balancing reserves. Effective management of grid congestion plays an important role in securing system operation and efficient resource utilisation. It is not possible to regulate resources to balance the system if these are stuck behind a bottleneck. The costs of reserves and availability of transmission capacity vary between areas and over time, which means that the distribution of reserves must be dynamically optimised to ensure that necessary grid capacity is available. This would reduce costs compared with applying fixed distribution of reserves over time.

Possible solutions that could be implemented by the TSOs:

- Clarification of a common Nordic specification for frequency quality, including requirements for frequency and balancing reserves.
- Further development of joint Nordic ICT solutions. Introduction of more advanced systems for supervision and control, and more automatisation of operational processes.
- Develop Nordic markets for all balancing products.

Possible solutions requiring broader collaboration:

- Finer time resolution in the energy and balancing markets.
- Stronger incentives for Balance Responsible Providers to maintain the balance by ensuring correct price signals.
- Review efficient and market based solutions for allocating transmission capacity to balancing and reserve markets.
- Harmonisation of products and market solutions for frequency and balancing regulation.

**Inertia**

Inertia in a power system is connected to the rate of change of frequency. With insufficient inertia, frequency drops can be too rapid, causing the frequency to reach the load-shedding value before reserves have reacted sufficiently. Higher volumes of RES, phasing out of nuclear units, and high imports through HVDC connections all reduce inertia levels. In 2025 the inertia, measured as kinetic energy, is estimated to be below the required volume of 120–145 GWs 1–19 per cent of the time depending on the climate year (based on analyses with historical reference period 1962–2012). The lowest kinetic energy values are observed during summer nights with high wind production. In the current Nordic power system (2010–2015), the estimated kinetic energy was below 140 GWs 4 per cent of the time or less; however, in 2009 the duration was approximately 12 per cent.

The main challenge lies in maintaining sufficient inertia in the system to guarantee operational security since insufficient inertia would put system stability at risk in the event of a large unit trip.

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Another challenge relates to the lack of minimum requirements i.e. a common understanding of how low a level of inertia the system can accommodate, and expectations of the future Nordic power system. Market solutions or incentives will be required to ensure that sufficient inertia is maintained in the system at all times.

The solutions for coping with low inertia can be split between legislative, market and the TSOs' own measures.

Possible solutions to be implemented by the TSOs:

- Setting minimum requirements for kinetic energy in the system.
- Limiting the power output of the largest units (generators and importing HVDC links) in situations with low inertia, to a level where the frequency remains within the allowed limits in the event of large unit trips.

Possible solutions requiring broader collaboration:

- In the short term, inertia in the system can be increased by running existing production units with lower average output.
- Adding more frequency containment reserves, including HVDC Emergency Power Control, or increasing the reaction speed of the reserves for getting faster responses during disturbances.
- Installing System Protection Schemes or using HVDC links.
- Adding rotating masses, such as synchronous condensers.
- Adding synthetic inertia to the system.

**Transmission adequacy**

Transmission capacity plays a key role in addressing the system challenges described above. Adequate transmission capacity enables cost-effective utilisation of energy production, balancing and inertia resources and helps to ensure the security of supply.

Each TSO in the Nordic region is responsible for developing the transmission system within its borders. The Nordic TSOs have published national grid development plans presenting both approved projects and project candidates. The very nature of the transmission system makes regional cooperation essential to achieve an effective power system. This is fully acknowledged by the Nordic TSOs, and joint grid development plans have been published since 2002. Identified potential transmission investments are subject to a bilateral study between the involved TSOs.

One challenge of transmission planning involves applying the correct assumptions and properly valuing all benefits. Uncertainty surrounding future developments has increased in recent years, making it more difficult to predict the future power system. In addition, not all power system benefits of transmission capacity are properly valued when evaluating transmission investments. The focus has historically been on commercial benefits, while there is a growing need to adequately value the security of supply. Consequently, there is a need to further develop cooperation with regard to modelling tool development and method improvement. Another difficulty relates to balancing Nordic, European and national perspectives in transmission planning. It is critical to address these issues today in order to successfully deal with predicted system challenges.

A second challenge involves maintaining operational security and an efficient market while reconstructing the grid. While development and increased application of live work will help meet this challenge the planned outages of grid components will nonetheless be very frequent in the coming decade, with resulting intermittently limited capacity. The investment portfolio shows that this is especially relevant for the next few years, since investments for the Nordic TSOs peak in 2018.

Possible solutions that could be implemented by the TSOs:

- Additional transmission capacity can alleviate the challenges with generation adequacy, flexibility and real-time balancing.
- Improving modelling tools and common understanding of the interpretation of findings, along with a robust scenario strategy. Improving methods of including additional values in transmission planning and in-depth analysis of which services that are valuable for the power system.

Possible solutions requiring broader collaboration:

- Clarification of differences and common goals for grid development in the Nordic region.

**The way forward**

The challenges listed need to be addressed. If no measures are taken, there could be severe consequences. The timeline in Figure 3 highlights the most important triggers (changes) which will exacerbate the challenges.  Leading up to 2025 and beyond, the risk of the identified challenges will increase. Action from the Nordic TSOs and other stake

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holders in the Nordic power sector will reduce the risk.

Improvement possibilities have been identified with regard to market design and operations. The Nordic TSOs have started several projects, including initiatives to boost knowledge about frequency, quality and handling of inertia; to develop a common market for balancing reserves, more finely tuned time resolution, full-cost balancing, cost-recovery and efficient balancing incentives, to stimulate demand side response and to secure more efficient utilisation of transmission capacity.

More extensive cooperation between the Nordic TSOs is a prerequisite for successful development and implementation of the available solutions; however, the Nordic TSOs cannot achieve everything on their own. Successfully stabilising the power system will require extended cooperation across the power sector. An example where cooperation between regulators and TSOs is necessary is the EU regulatory cross-border cost-allocation (CBCA) tool, which the Nordic TSOs do not believe is an efficient way to speed up market integration.

Possible solutions have been identified for each challenge analysed in this report. Some of these solutions are market based where there need to be an agreement of which market model to develop and implement. Other solutions are technical solutions where cost and cost-sharing are the main issues. A third category of solutions is knowledge related – more insight is needed in order to evaluate the solutions. Many of the proposed solutions cannot be developed and implemented without extensive collaboration with the regulators and the power industry. The power system is becoming more complex and more integrated. Cooperation both across country borders and between different stakeholders in the Nordic power system is a prerequisite for success.

Research, development and demonstrations will also be required, especially where future solutions are unclear, and/or contain new technology or concepts. By further developing the R&D cooperation between the Nordic TSOs, an increased commitment and more efficient information sharing is acheived.

The Nordic TSOs will follow up this report with a second phase that will further examine the solutions identified in this report. The aim of the next phase is to take the cooperation a step further and agree on measures.

## Timeline of the identified challenges

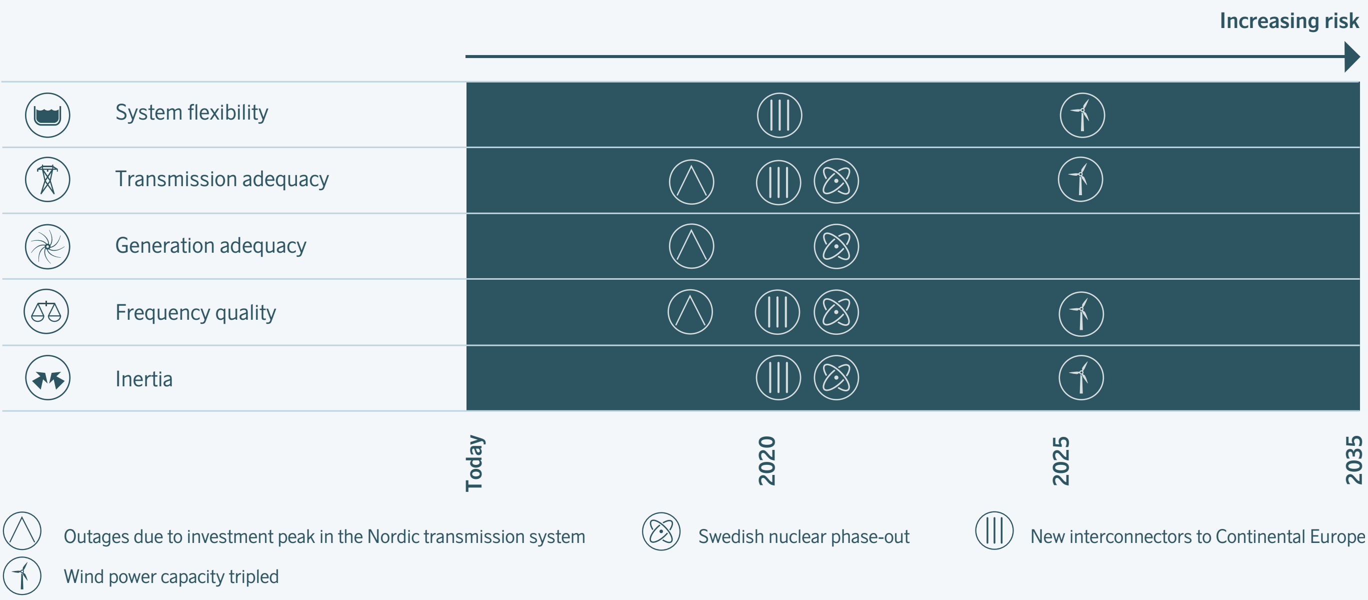


*Figure 3 Timeline of the identified challenges. The figure include four triggers (changes) that will exacerbate the challenges. Leading up to 2025 and beyond, the risk of the identified challenges will increase if no measures are taken.*

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# List of abbrevations

## List of abbreviations

| | |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| aFFR | Automatic Frequency Restoring Reserves |
| AMS | Automatic Metering System |
| CACM | Capacity Allocation and Congestion Management |
| CBA | Cost-Benefit Analysis |
| CHP | Combined Heat and Power |
| CoBA | Coordinated Balancing Areas |
| EC | European Commission |
| EENS | Expected Energy Not Supplied |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| EPC | Emergency Power Control |
| FCR | Frequency Containment Reserves |
| HVDC | High Voltage Direct Current |
| ICT | Information and Communications Technology |
| LOLE | Loss of Load Expectation |
| mFRR | Manually Frequency Restoring Reserves |
| MSG | Market Steering Group |
| NOIS | Nordic Operator Information System |
| NSL | North Sea Link |
| NTC | Net Transmission Capacity |
| PMU | Phasor Measurement Unit |
| PV | Photovoltaics (Solar Power) |
| RES | Renewable Energy Sources |
| RoCoF | Rate of Change of Frequency |
| RSC | Regional Security Coordination Service Provider |
| R&D | Research and Development |
| SOA | System Operation Agreement |
| TSO | Transmission System Operator |
| TYNDP | Ten-Year Network Development Plan |

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# The Nordic power system 2025

## 1.1 Introduction

The Nordic power system is changing. More Renewable Energy Sources (RES), more transmission capacity between the Nordic power system and Continental Europe, and changes in consumption are resulting in significant challenges with regard to forecasting, operating and planning the power system. These changes are driven by a climate change agenda, technical development, including digitalisation, and a common European framework for markets, operation and planning. This system transformation has already started, but will be even more apparent in 2025.

The Nordic power system is a synchronous area[1] with a common frequency. Consequently, imbalances affect the frequency and power flows in the entire system. With Europe moving towards a more integrated power system and the Nordic countries becoming more interlinked, the Nordic countries are even more dependent on each other. This is necessitating further harmonisation of the existing Nordic market solutions and preparations for efficient integration with the European markets.

The Nordic Transmission System Operators (TSOs) have a long history of collaborating on operations, planning and market solutions. The TSOs now see a need to establish a coherent system-wide collaboration in order to cooperate more efficiently. A common understanding of the way the changes will affect the Nordic power system and how the TSOs should respond is required. The purpose of this report is to enable the four Nordic TSOs, Svenska kraftnät, Statnett, Fingrid and Energinet.dk, to jointly agree on priorities for the Nordic power system and to contribute to a constructive collaboration. We aim to create a common understanding of the major challenges and opportunities the Nordic power system is facing as we approach 2025. Landsnet is not included in this strategy.

In this chapter, the ongoing and predicted changes in the Nordic power system in the period leading up to 2025 are introduced. This chapter also contains a brief discussion of the ensuing challenges, as well as the Nordic TSOs' "best estimate" scenario for 2025.

## 1.2 Uncertainties will shape the future Nordic power system

While the Nordic power system undoubtedly faces major changes, significant uncertainty attaches to the magnitude and pace of these changes, and how these will affect the power system. The location of new renewable energy generation will have a significant effect on the need for new transmission lines. Future regulations, including subsidy schemes, will thus have a major impact on the design of the Nordic power system. Technical developments are also uncertain. For example, the role of demand response depends on the level of system automatisation while the suitability of battery storage as a flexibility provider will be contingent on the cost and capacity of the batteries of the future. Technical developments are facilitating closer coupling between different synchronous areas.

Electricity prices are currently very low, both in the Nordic countries and the rest of Europe. The main reasons for this are low price levels for coal, gas and $CO_2$, and a rising share of subsidised RES in the energy mix. In the Nordic area, the growing volume of unregulated generation, in particular during summer, and in periods of high water inflow to hydropower plants' reservoirs, is further depressing prices. The current low price level in the market is not incentivising new investments in any type of power generation. In addition, existing baseload generation is struggling with unprofitable operations. The early commissioning of thermal power, especially Swedish nuclear, illustrates this point. It is uncertain how electricity prices will develop as we approach 2025. We are likely to see a rebound due to a gradual rebalancing of the global fuel markets, though continuously low prices all the way to 2025 is also a possible scenario. The market tools and the market design need to adapt to this new low-price situation. Lack of incentives for investors could have adverse long-term effects on the security of supply.

In order to better understand the uncertainties, and to be prepared to deal with these, the Nordic TSOs have a strong focus on research and development. The TSOs have collaborated within research and development since the early 1990s. Today, the Nordic R&D group coordinates research and development projects of common interest, shares information about each TSO's R&D strategies, future R&D needs and best practices and, acts as a common Nordic

*[1] The Nordic synchronous system consists of the electricity systems of Finland, Sweden, Norway and the eastern part of Denmark (Sjaelland) while the western part of Denmark (Jutland) is synchronised with the Continental European system. Unless otherwise specified we will include all of Denmark (i.e. also Jutland) when analyzing and discussing the Nordic power system.*

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# The Nordic power system 2025

voice with regard to ENTSO-E's R&D and Innovation Committee. The Nordic TSOs are currently running eleven common R&D projects based on common Nordic needs.

### 1.3 Main trends towards 2025

The structural changes in the power system will challenge the way we traditionally think about and operate the Nordic power system. The main changes are:

- The closure of thermal power plants.
- The share of RES in the generation mix is increasing while the capacity of coal and gas is declining.
- Swedish nuclear power plants will be decommissioned earlier than initially planned while Finland is constructing new nuclear plants.
- More interconnectors between the Nordic power system, the Continental European system, and other systems (the UK, Russia, the Baltic system).

In order to meet the challenges of climate change and energy security, which are on the European Commission's agenda (ENTSO-E 2014), a similar transition in power systems is expected elsewhere in Europe over the next ten years. Further RES integration and increased electrification of both the transport and household sector are expected. Regional coordination is, and is becoming even more, critical to the secure operation of an interconnected European power system. The functioning of cross-border markets, and regional cooperation is therefore one of the main vehicles for delivering the Energy Union, and securing benefits on a European and national level. The network codes facilitate harmonisation, integration and efficiency of the European electricity market, and are intended to enable efficient cooperation between all stakeholders including the TSOs. However, this will entail more formalised and standardised regulation that will prolong the process for modifications.

Historically, the Nordic power system has experienced problems on cold winter days with high demand and limited generation and transmission capacity. It was relatively easy to predict in which period this could happen, and plan accordingly. Now, in addition to hours of peak demand, problematic situations may also include hours with low load and high wind production. These hours are much more difficult to predict and prepare for. This results in low inertia, as the thermal power plants tend to close down in these situations.

The changes in the power system will influence existing, and create new, market participants. The roles and interaction of the participants will change. New participants, e.g. prosumers[2] and aggregators[3], will challenge current business models, and will require new ICT solutions. The digital transformation of the power system; smart meters, energy management systems, automated demand response and microgrids could be key enablers in the restructuring of the Nordic power system. The Nordic TSOs are developing these enablers both at a national and a Nordic level. These ICT (information and communications technology) and market solutions will play a central role in the transition of the power system. The system will be more complex, more integrated and more automated. While this is an important trend, its exact impact in 2025 is highly uncertain.

All these changes suggest that it will be even more important to look at the whole picture, and to plan the transmission grid in relation to the market and the response from both generation and consumption.

*[2]A prosumer is an end-user that both produces and consumes power.*
*[3]An aggregator collects and manages small-scale consumption, and can activate participation in reserve and balancing markets.*

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# The Nordic power system 2025

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## 1.4 Our scenario for 2025

The Nordic Grid Development Plan (Energinet.dk, Fingrid, Statnett and Svenska kraftnät, Landsnet 2014) and each country's grid development plans are used as a basis for systemising the development of the grid. Transmission capacity has increased in recent years and will continue to expand in the future, as illustrated in Figure 4. These vast investments in the Nordic grid over the next ten years will reduce bottlenecks and improve system flexibility. The total investment portfolio will peak in 2018.

**Total investments by the Nordic TSOs (MEUR/year)**

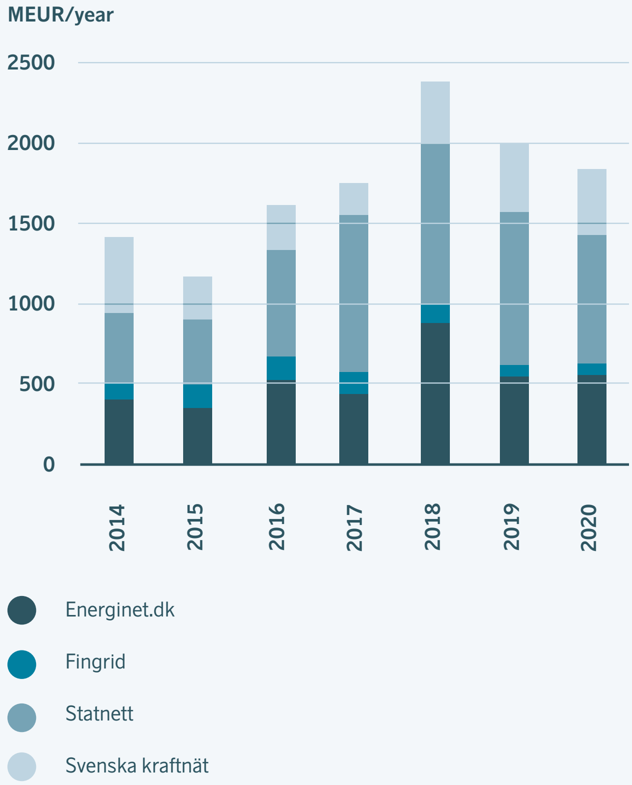


*Figure 4 Total investment portfolio for the TSOs 2014–2020.*

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# The Nordic power system 2025

Figure 5 shows the Nordic TSOs' best estimate scenario for 2025. The scenario is based on an expectedly moderate growth in consumption, existing climate and energy policies, and known investment and de-commissioning plans for production capacity.

By 2025, the connection capacity between the Nordic power system and the power systems of the European Continent, the Baltic system and the UK will almost have doubled, see Figure 6.

The main challenges we foresee in our scenario for 2025 are:

- An increased demand for flexibility.
- Securing transmission and generation adequacy to guarantee security of supply.
- Maintaining a good frequency quality.
- Securing sufficient inertia in the system.

These challenges are further analysed and discussed in the following chapters. We aim to systemise and prioritise the various challenges, many of which we are already facing today, but which will be more prevalent as we approach 2025.

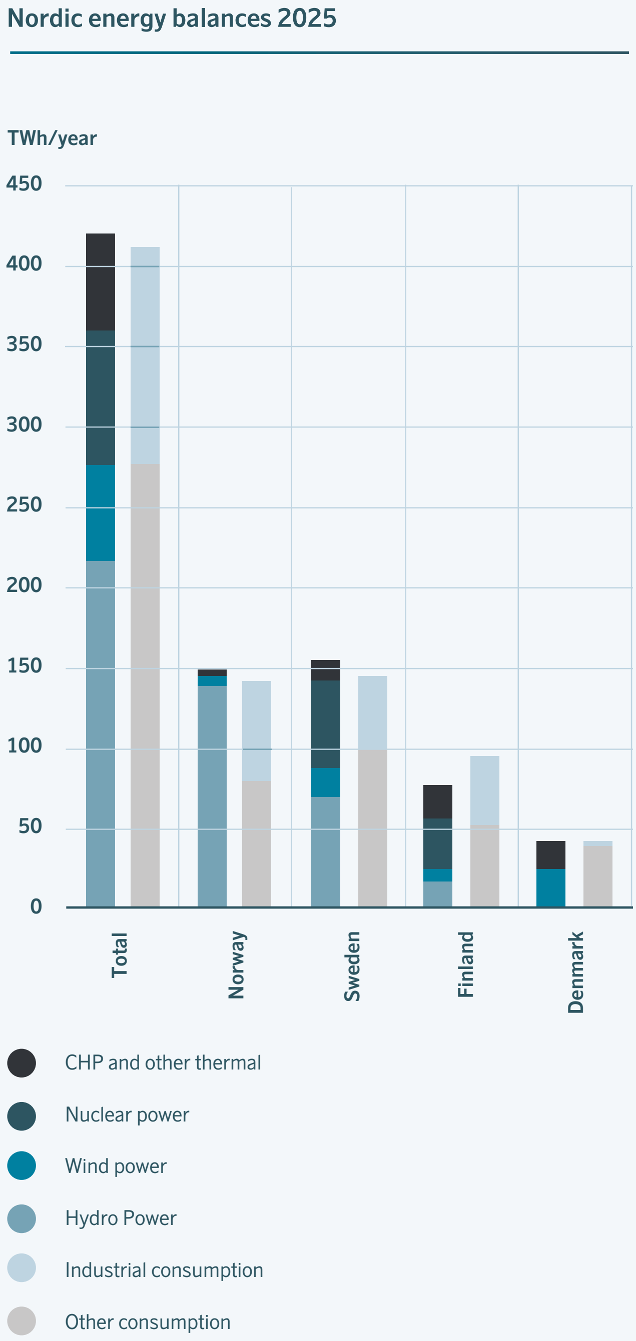


*Figure 5: An estimate of electricity production and consumption in the Nordic power system in 2025 as a result of market simulation performed in 2015.*

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# The Nordic power system 2025

**Overview of existing HVDC interconnectors and HVDC interconnectors under construction**

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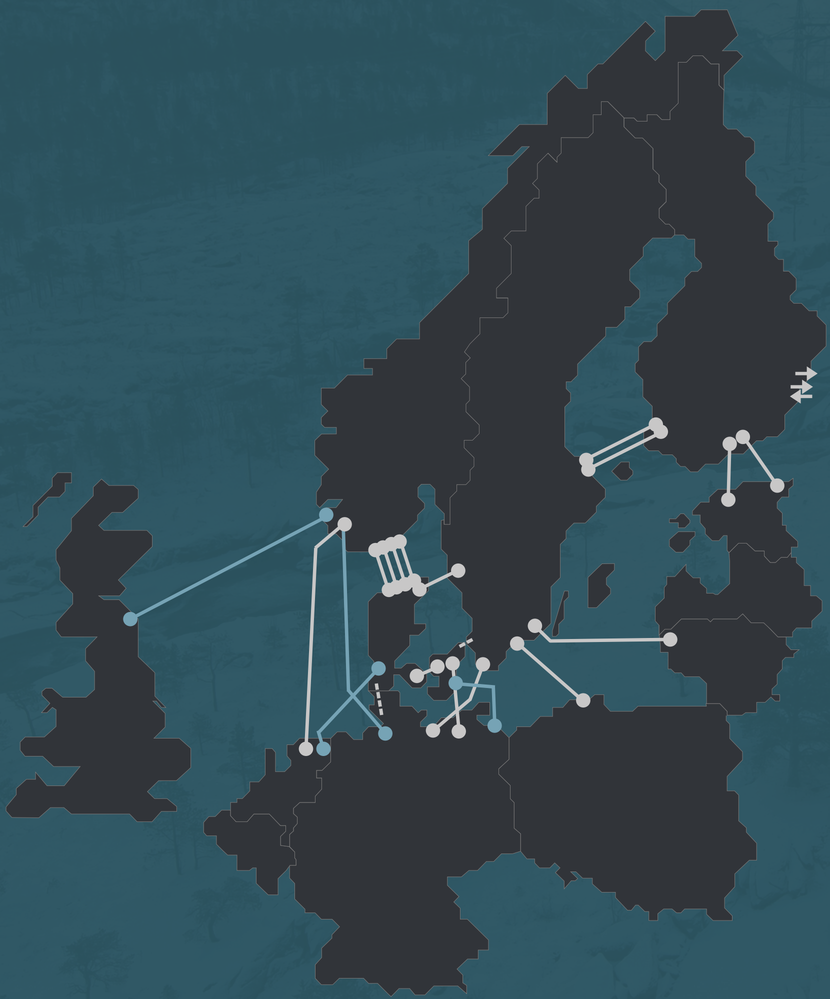

*Figure 6 Overview of existing and planned HVDC interconnectors in the Nordic power system. Only those planned HVDC interconnectors with a final investment decision are included.*

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# System flexibility

## 2.1 Definition of system flexibility

One of the specific characteristics of the power system is the need to maintain the total amount of production and consumption at the same level at all times. This requires flexibility, which can be defined as the controllable part of production and consumption that can be used to change input or output for balancing purposes. Another category is energy storage that can act as both consumption and production, dependent on the situation. Examples of time horizons and corresponding needs for flexibility include:

- Long-term – in order to balance the variations in generation and consumption between seasons and years
- Medium-term – balancing between months, weeks and days
- Day-ahead – establishing a balance hour by hour for the next day
- Intraday – adjusting the balance hour by hour for the same day
- Operation – fine-tuning the already balanced system minute by minute, second by second

Examples of flexibility sources include hydropower plants with reservoirs, coal and gas power plants, price-dependent consumption, batteries and hydro plants with the capacity to pump up water for later use. Intermittent wind, run-of-river hydro and PV plants can also provide short-term down-regulation when they are producing. They also have a potential for short-term up-regulation if production is reduced in advance.

## 2.2 Existing production flexibility – an increasingly scarce resource

The high percentage of hydro production with reservoirs in the Nordic region provides large volumes of relatively cheap flexibility, both in the day-ahead market and in the operational hour. The reservoirs provide excellent opportunities to accumulate water for a long time, and the cost of ramping up and down these plants is close to zero. In addition to the hydropower, the Nordic countries have a significant volume of flexible thermal coal and gas power plants that can also provide both long- and short-term flexibility, though at a higher cost than hydropower.

Until now, the flexibility provided by the hydro plants with reservoirs has been large enough to cover most of the flexibility needed in Norway and Sweden, and a significant proportion of the flexibility demand in Denmark and Finland. Flexible thermal power plants and connections abroad mainly cover the residual demand. This has resulted in a relatively low price volatility in the day-ahead market and relatively low operational balancing costs. This will probably change in the period leading up to 2025.

- Demand for flexibility is increasing, both in the day-ahead market and in the operational hour.
- At the same time, the flexibility provided by existing hydro plants is limited and thermal production capacity is declining.

A higher market share of intermittent renewables will be the main driver of increased demand for flexibility in the period leading up to 2025. In periods of low consumption and high production from wind, solar and run-of-river hydro, other production units need to provide more flexibility in the day-ahead market by ramping down their production. Meanwhile, forecasting errors affecting a larger proportion of total production will increase the need for balancing closer to, and within, the operational hour.

With increasing transmission capacity towards the Continental European, the UK and the Baltic systems, the Nordic region both provides and receives flexibility. However, the new capacity will contribute to increased competition for the low cost flexibility provided by hydropower. This will increase the value of hydro production, and lead to higher short-term price volatility in the day-ahead market and higher balancing costs in the operational hour. In addition, the reserve requirements of system operation may increase due to greater changes in the power flow and larger imbalances.

The options for further redispatching of flexible production are limited by numerous factors. We are already experiencing periods where hydro plants are reaching limits and thus cannot provide any additional flexibility. The same is the case for the thermal units. In Statnett's market simulations for 2025, the following occurs more frequently:

- Hydro plants with reservoirs and thermal plants are producing at full capacity, typically during high consumption periods in the winter, and low production from wind and run-of-river hydro.

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# System flexibility

- In the summer, production from hydro plants with reservoirs and thermal plants is close to zero. This occurs in periods of low consumption and high output from wind and run-of-river hydro, forcing hydro plants with reservoirs and thermal power plants to hold back production. Figure 7 illustrates the low levels of regulated hydro production during summer nights in dry years.

The first situation leads to more price peaks in the day-ahead market, typically at the same level as continental peak prices. In the operating hour, the resources for up-regulation become scarcer. This increases prices in the balancing market.

In the second situation, characterised by low consumption and high wind and run-of-river production, the result is very low prices in the day-ahead market. In the operating hour, the options for short-term down-regulation are more limited. This can result in higher prices in the balancing market. An additional challenge in this kind of situation is that the flexible hydro and thermal plants will not deliver any inertia to the system since they are disconnected (see chapter 5).

All other factors remaining equal, an increased scarcity of flexible production in the Nordic region will have several consequences for the power system:

- Increased short-term price volatility in the day-ahead market, more in line with European Continental prices. This will occur more in the southern and eastern parts of the Nordic region than in the northern part of the region.
- Reduced hourly price differences between the southern parts of the Nordic region and the European Continent.
- Higher balancing costs.
- Less inertia during periods of very low production from nuclear, other thermal and large hydro plants.
- More power transmission between the hydro stations with reservoirs and the consumption centres and the interconnectors in the south.

### 2.3 Continental development reduces the available flexibility

The continental market has currently sufficient thermal production capacity to cover the demand during the periods of low production

**Simulated production from regulated hydropower in Norway and Sweden combined**
For different time slots in the day

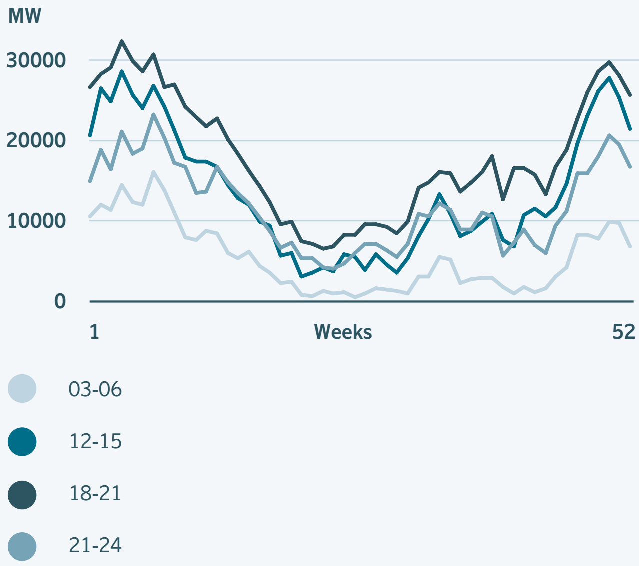


*Figure 7 Simulated production from regulated hydropower in Norway and Sweden combined. Average of five dry years in 2025.*

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# System flexibility

from intermittent renewable sources. However, the increasing share of intermittent renewables reduces both the usage and profitability of the thermal plants, and without sufficient remuneration, a significant share of the thermal capacity will shut down. If this happens, the capacity margin[5] in the day-ahead market will be gradually tighter over the next decade. This will affect the Nordic countries since there is a probability of having a tight margin on the Continent and in the Nordic area at the same time.

The UK and France are establishing capacity markets and several other countries are considering the same, however not the Nordic countries. It is uncertain, how these markets will be operated towards 2025, and to which extent the consumption will participate. In addition, Germany has chosen to establish a strategic reserve instead of a capacity market. This makes it more likely that the capacity margin in the European continental day-ahead market will be tighter. Statnett made an analysis that investigates the consequences of not having capacity markets in Europe (Statnett 2015a). The main conclusion is that this will lead to less thermal capacity in the day-ahead and balancing markets, and therefore more numerous and higher price spikes. The study also indicates higher price peaks in the hours with a tight margin in the Nordic countries.

### 2.4 Large potential for new flexibility in the Nordic region

There is large technical potential for expanding available flexibility within the Nordic area, although they offer different potential for flexibility. Some new possibilities are for example:

- Consumer flexibility – households, energy-intensive industry, heat and transport sector
- Expanding the flexibility of hydro plants by installing additional turbines and pumps
- Utilising intermittent renewable wind, solar and hydro production for balancing purposes
- Installing batteries combined with solar energy
- Constructing peak load gas turbines
- Rebuilding existing CHP plants to make them more flexible
- Utilising nuclear plants in balancing markets

**Hourly observed day-ahead prices in Germany and southern Norway**

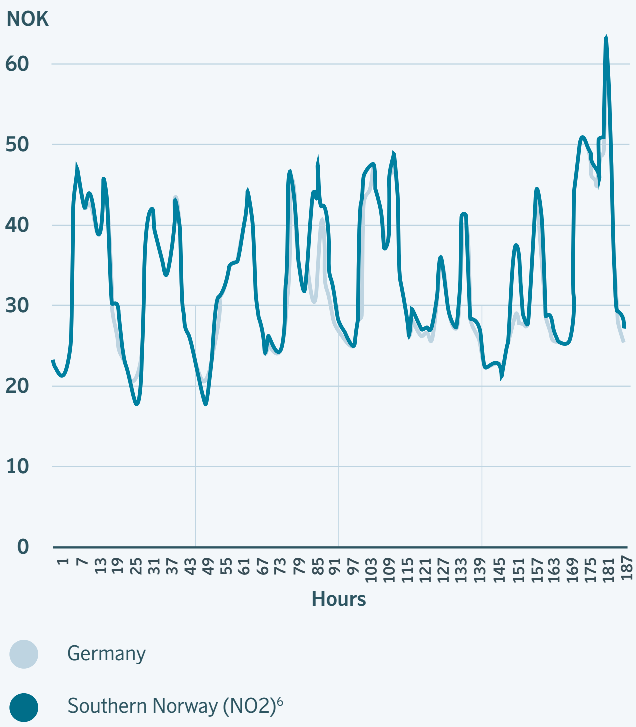


*Figure 8 Hourly observed day-ahead prices in southern Norway and Germany – Week 2, 2016. Because of capacity constraints within the hydro system, southern Norway is subject to the exact same price volatility as in Germany. In this case, the socio-economic benefit of adding more transmission capacity is low. This illustrates the link between day-ahead prices and capacity constraints.*

[5] *The difference between the available generation capacity and consumption.*
[6] *For the bidding zones in the Nordic countries please refer to Nord Pool: http://nordpoolspot.com/maps/#/nordic*

2

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# System flexibility

Energy-intensive industry in Finland, Sweden and Norway can provide more flexibility both in the day-ahead and the balancing market. The consumption of households has been highly inflexible so far, but with the introduction of smart metering and the resulting opportunities to manage household equipment more astutely, this may change. This will enable households to shift some of their consumption from peak hours to off-peak hours. How significant the overall contribution from the demand side will be in the period leading up to 2025 is however uncertain, and will depend on both technological developments and economic incentives.

There is major technical potential to increase hydro generation capacity, in particular in the southern part of Norway. The water Framework Directive might constrain this possibility and it is hence important that the implementation of the directive is done with as little impact on the hydro regulation potential as possible. In addition, several studies have demonstrated a technical potential for pumping plants running into thousands of megawatts. This would require huge investments[7] and would not be profitable under current market conditions.

Wind, solar and run-of-river hydro plants always have the possibility of down-regulating their production. They can also deliver up-regulation if production has been reduced in advance. Combined heat and power production with a closer interaction with the heat market can also make an increasingly important contribution, especially during periods of low electricity consumption and high production from wind and run-of-river hydro.

### 2.5 Challenges and possible solutions in the next decade

The power system is increasingly experiencing higher scarcity of existing production flexibility. However, there is significant potential for adding new flexibility. In a well-functioning market, a severe shortage of flexibility should therefore be avoidable. It is uncertain whether the markets of today can solve this challenge. Will the economic incentives be strong enough? Are regulatory or technological obstacles or delays in developing new market designs hindering the transition towards a system with a more diversified supply of flexibility?

More short-term price volatility in the day-ahead market and periods of higher prices in the balancing markets should provide incentives for expanding flexibility, which suggests that the market should be

[7] *New tunnels represent the main cost*

#### Regulating power in the Nordic countries

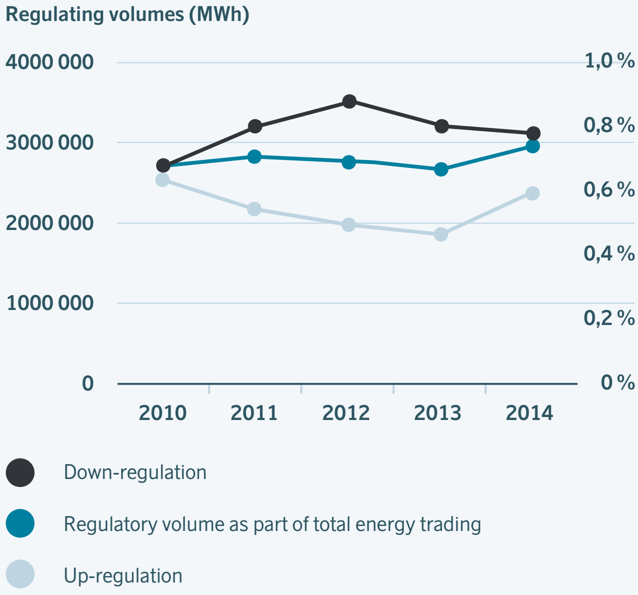


*Figure 9 Observed volumes for up and down-regulation 2010–14. The curves show a stable need for up-regulation and down-regulation during this period. However, we expect a need to increase – with more RES and interconnectors in the years leading up to 2025.*

# 2

# System flexibility

able to solve the problem. However, challenges could arise if either the change is too rapid for new flexibility to be found or if the price signals are distorted, for instance, by unsuitable RES subsidy schemes or fixed prices for end-users. Such market imperfections can make the transition less smooth and pose challenges for the operation of the power system in coming years. In severe cases, it could lead to hours without price formation in the day-ahead market, and periods of insufficient available balancing resources in the operational hour. It is also possible that these challenges will manifest themselves in geographical sub-areas even though there is sufficient flexibility on a system level.

One prioritised area for TSO cooperation is to develop more knowledge about the technological and economical potential for new flexibility in order to gain a more precise picture of the possible challenges of balancing the system in the coming years. Other possible solutions that could be implemented by the TSOs are:

- Developing the power and reserve markets to more accurately reflect the changing fundamentals of the power system. More finely tuned time resolution in the day-ahead and intraday markets as well as the balance market, and more emphasis on the intraday markets would, for instance, reduce the imbalances and hence the need to balance resources within the operational hour.
- Utilising the transmission capacity more efficiently – continuing to evaluate different capacity allocation options.
- Restrict ramping on each HVDC interconnector even further.

Possible solutions requiring broader collaboration:

- Ensuring that the rules and regulations of the market facilitate the most cost-effective development and utilisation of available flexibility.
- Utilising the information provided by the automatic metering system (AMS) to introduce demand response.

The challenges presented by a shortage of available flexibility, and the possible solutions, are further discussed in Chapter 3 (Generation adequacy) and Chapter 4 (Frequency quality). The flexibility issue also impacts the benefits of building new transmission capacity and the availability of inertia.

# 3

# Generation adequacy

## 3.1 Introduction

Generation adequacy expresses the ability of generation capacity to match the load in the power system.

As larger amounts of renewable energy are integrated into the power system there is a move from regional to European markets and there is hence an increasing need to have a Pan-European overview of generation adequacy. At the same time, reduced profitability of conventional power generation represent a growing potential challenge to future capacity generation adequacy. Generation adequacy relates to the part of security of supply concerning the ability of the power system to supply customers' aggregate power requirements. The ongoing and foreseen changes of the power system will make it more difficult and expensive to fully eliminate the risk of capacity shortages. This implies a need for a clear definition of generation adequacy, and discussions of the socio-economic best instruments to use in order to maintain generation adequacy.

In January 2016, the Nordic power system experienced a market situation with a very tight demand-supply balance in the day-ahead market (Figure 10), and following high prices in most of the Nordic bidding zones.

Along with the first market signals of a tighter demand-supply balance, generation adequacy studies are highlighting an increasing risk of energy not supplied to the consumers. Additionally, the recent assessment from ENTSO-E shows that an increasing number of countries plan to rely on imports to maintain adequacy in the period leading up to 2025, and a growing importance of cross-border exchanges in the pan-European system.

In order to assess whether or not increasing dependency on neighbouring countries and increasing shares of renewable energy pose a challenge for the Nordic power system, it is important to make a common assessment of capacity adequacy. Therefore, future analyses of adequacy should be based on a jointly developed methodology that adopts a probabilistic modelling perspective for all hours of the year. This would facilitate a more consistent assessment of variable renewable energy generation, projected interconnector flows, demand-side management and flexibility in the market.

### Demand-supply balance in the Nordic Power system on 21 January 2016

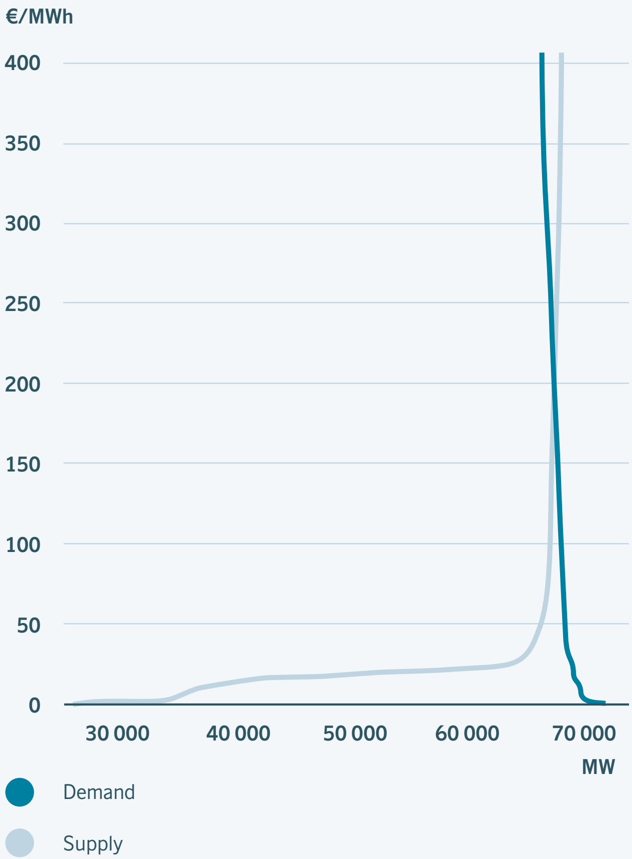


*Figure 10 Demand-supply balance in the Nordic power system on 21 January 2016, showing a very tight demand-supply balance. Market Data from Nord Pool Spot.*

# 3

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# Generation adequacy

The main challenges for the Nordic power system with respect to generation adequacy are:

- **Market influence:** Increasing shares of renewable generation and reduced profitability of conventional power generation result in reduced capacity from nuclear and other thermal power plants. Inadequate generation should also be viewed in the context of market developments. If price signals are too low for market participants, the latter cannot react adequately, either in terms of short-term responses to shortage situations, or in terms of long-term investment decisions. Thus, generation adequacy is a question of getting prices right.
- **Lack of cross-border adequacy assessment:** Expanding market integration and increasing cross-border capacity means that, as a minimum, regional adequacy assessments will be required to properly evaluate shortages and thus identify the right basis for appropriate mitigation measures. However, it is also necessary to acknowledge that some adequacy challenges occur in local situations, e.g., where demand can be "locked-in" due to faults on transmission lines.
- **Need for methodologies:** Traditional adequacy methodologies are national and deterministic. These include parameters like available thermal capacity and seasonal peak load demand. Consequently, adequacy assessments disregard capacity based on variable power sources, underestimate the value of transmission capacity, and do not cover the uncertain nature of faults in components in the power system.

## 3.2 Challenge 1: Securing sufficient, trustworthy capacity through market signals

The Nordic region as a whole is receiving an increasing share of RES. At the same time, low wholesale electricity prices are reducing revenues from traditional power plants, which in turn lead to a decreasing capacity for thermal power plants such as coal and nuclear. Demand is not expected to change significantly since economic activities are only expected to pick up slowly and use of power in other sectors (e.g. heating and transport) is not forecast to increase dramatically.

In overall terms, an evolving common European market is providing the basis for determining production capacity in the power system. Adequacy refers to the ability of the power system to supply customers' aggregate power loads at all times, taking into account the scheduled and unscheduled outages of system components. For the market to serve that purpose, the regulatory framework and the market design have to facilitate proper market dynamics.

There must be room for higher price max and that price signals reach market participants. If proper price signals do not reach market participants, the latter cannot react adequately, be it short-term responses to shortage situations or long-term investment decisions.

## 3.3 Challenge 2: Increasing adequacy issues in the Nordic power system

### 3.3.1 ENTSO-E and Nordic approaches

ENTSO-E's generation adequacy assessment is based on a national power balance-based approach, which includes parameters such as "available thermal capacity" and "seasonal peak load demand", but often disregards capacity based on intermittent energy sources. (ENTSO-E 2015d)

The Nordic countries (mainly TSOs) have carried out a number of studies that take account of national adequacy issues, including assumptions on interlinked neighbouring countries. Some of the studies are deterministic while others are probabilistic.

Please note that the output figures are not direct assumptions of blackouts since additional measures can be used in operations. However, it is important to highlight that these kind of models often overestimate actual flexibility. They give an indication of the risk of adequacy problems, but have a tendency to underestimate actual risk.

### 3.3.2 Danish studies

In 2015, both Energinet.dk and the Danish Energy Agency conducted adequacy assessments based on probabilistic approaches. The models were spreadsheet-based, and built on consumption, wind and solar power profiles. (Energistyrelsen 2015) Overall, the analyses do not reveal major adequacy issues in the Nordic countries. The sensitivity analyses in one of the studies conclude:

- Any rise in the risk of failure on interconnectors would have a rela-

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# Generation adequacy

tively large impact on risks for Danish generation adequacy.

- A faster shut down of some of the Danish decentralised and centralised power plants (compared to the 2025 scenario presented in chapter 1.4) increases the risk of Danish generation adequacy problems. This effect is stronger in eastern than in western Denmark.

According to Energinet.dk's generation adequacy assessment for Denmark, generation adequacy in eastern Denmark will come under pressure in 2018, as the strategic reserve of 200 MW has not been approved. By 2020, the level of security of supply will no longer be critical, given expected developments in neighbouring countries and the estimated domestic capacity. If more power stations than expected are closed down in eastern part of Denmark or the Kriegers Flak interconnector is delayed, new initiatives may be required to maintain security of supply levels in eastern part of Denmark.

### 3.3.3 Finnish studies

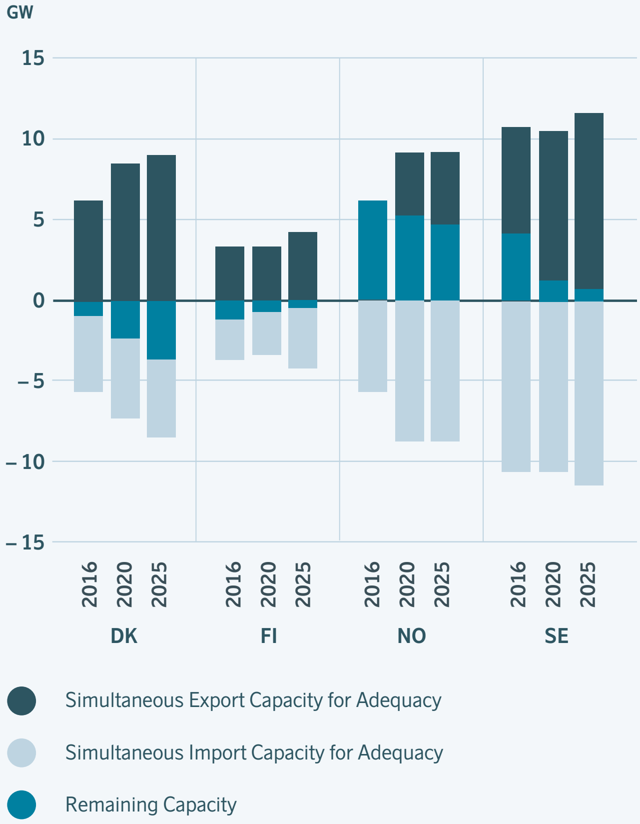
In 2015, a deterministic study of the adequacy of power capacity was conducted in Finland for the period leading up to 2030 (Pöyry 2015). The study concluded that the capacity deficit in Finland in relation to peak demand will be at its highest around 2018. It also concludes that Finland will be dependent on imports until 2030.

Fingrid has developed a method of assessing the power adequacy of a power system with stochastic characteristics and conducted a probabilistic study of adequacy in Finland (Tulensalo 2016). The study focused on the day-ahead market and system service reserve capacity was categorised as unavailable. The occurrence of faults affecting both generation units and cross-border interconnectors was taken into account. Exchanges with Russia were not taken into consideration in the study.

Loss of load expectation (LOLE) shows how many hours' loss-of load can be expected during a year. These figures are not the same as blackout or brownout, but only provide an indication of potential stressed capacity balances that will need to be managed. Finally, the capacity margin shows any missing generation capacity or demand flexibility.

#### Scenario outlook & adequacy forecast from ENTSO-E

The recent assessment from ENTSO-E shows an increasing number of countries relying on imports to maintain adequacy between 2016 and 2025. At the same time it shows an increasing role og crossborder exchanges in maintaining adequacy in the Pan-European system.




**Main conclusions:**
Even though some of the Nordic countries are dependent on imports, the overall picture is that interconnections are sufficient to address the import needs, and seen as a whole the total remaining capacity is also sufficient to cover peak demand.

• Some countries, e.g. Belgium, Denmark, Finland and Sweden are structurally dependent on imports through the period analysed 2016–2020–2025.

• The need for imports appearing at the beginning and at the end of the year indicates the effect of low temperatures and a corresponding increase in demand.
Source: (ENTSO-E 2015d)

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# Generation adequacy

| Finland | | | Capacity margin (MW) | |
|---|---|---|---|---|
| Simulation year | LOLE (h) | EENS (MWh) | In a medi-an year | In a cold year once in 10 years |
| 2012 | 0.01 ± 0.14 | 1.4 ± 29 | 1400 | 890 |
| 2014 | 0.07 ± 0.09 | 15 ± 24 | 990 | 490 |
| 2017 | 1.8 ± 0.54 | 490 ± 220 | 360 | −290 |
| 2023 | 5.3 ± 1.1 | 1800 ± 550 | 90 | −680 |

*Table 1 The simulation results of the case studies for 2012–2023. Loss of load expectation (LOLE) and expected energy not supplied (EENS) are presented with a 95 per cent confidence interval for all simulated cases (Tulensalo, 2016). The simulation results show that there is an increasing risk of energy not served over the next ten years.*

In overall terms, the Finnish studies show that the EENS will increase over the next ten years in Finland, and that the dependency on neighbouring countries will also rise.

### 3.3.4 Norwegian study

In 2015, Statnett conducted a deterministic study (Statnett 2015a). The study concluded that in 2030 Europe will have a negative capacity margin at an average of 0.3 per cent of the time, but that this will vary significantly between climate years. During the worst years, the capacity margin will be negative roughly 2 per cent of the time, and some countries will be close to rationing.[8] These results assume a long-term market balance and do not take into account the probability of available grid and generation.

The study shows that although sharing back-up capacity helps in many hours, the potential is limited during periods of high residual demand (demand after deducting solar and wind power production). The study analyses correlations in European weather patterns based on weather series. During winter, residual demand in one country is more than 60 per cent dependent on the residual demand in neighbouring countries. This poses no problem in normal conditions; sharing of back-up capacity and flexibility generally functions well. The problems will arise on days when residual demand is very high in several countries at the same time.

**Duration curve of the minimum remaining capacity index**

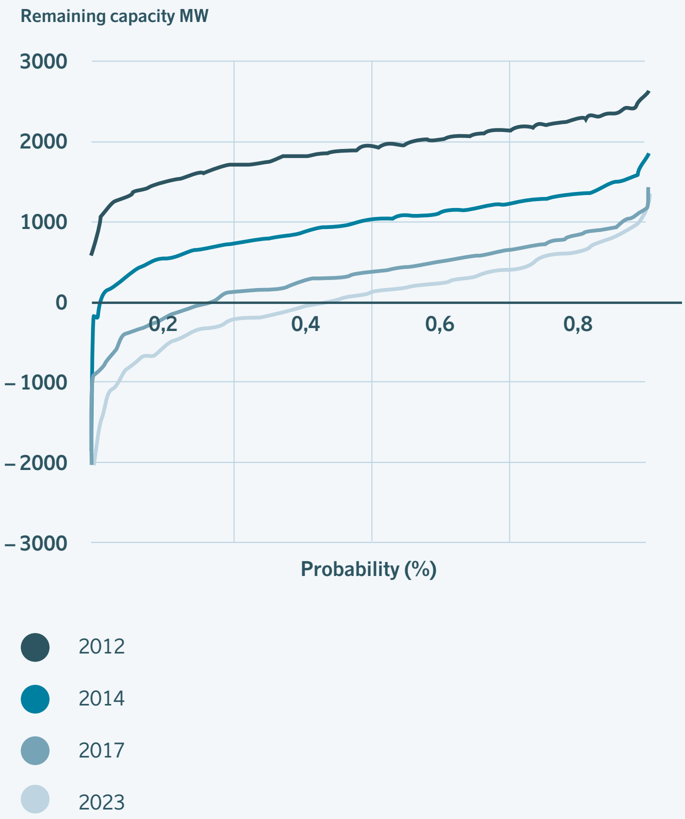


*Figure 11 Duration curves for Finland of the minimum remaining capacity index during the simulated years 2012, 2014, 2017 and 2023. (Tulensalo 2016)*

[8] *It should be noted that this conclusion is based on the assumption of an energy-only market, and hence does not take account of any capacity mechanisms.*

### 3.3.5 Swedish study for 2030

During 2015 Svenska kraftnät developed a new method for assessing the Swedish adequacy situation based on probabilistic modelling. The spot market for 2030 was modelled without any strategic reserves. Consequently, the loss-of-load in the simulations should be interpreted as a situation when the spot market does not clear. In addition, the market is modelled without demand price elasticity and demand flexibility, which would improve the situation.

| 2030 | LOLE (h) | EENS (MWh) | Capacity margin (MW) |
|---|---|---|---|
| SE1 | 0.04 | 0.3 | 145 |
| SE2 | 0.04 | 0.6 | 243 |
| SE3 | 1.1 | 453 | 830 |
| SE4 | 1.1 | 122 | 223 |

*Table 2 Results from adequacy analyses of the spot market in the Swedish bidding zones. Please note that these figures are not the same as blackout or brownout figures, but only provide an indication of potential stressed capacity balances that will need to be managed. Finally, the capacity margin shows any missing generation capacity or demand flexibility. The results show that in 2030 SE3 will have the highest risk of energy not supplied followed by SE4. Both SE1 and SE2 have a very low risk.*

If we are looking only at the expected capacity margin, Sweden should not experience any shortage. If, instead, the individual simulations are analysed, the picture is somewhat different. Figure 12 shows the simulated capacity margin for 2030 and in 70 out of 500 simulated years the spot market will not clear, i.e. the margin is negative. If a strategic reserve of 750 MW is assumed, 17 out of 500 simulated years will still show lack of capacity. This result can also be expressed as a 3.4 % probability of having at least one hour with the loss of load in 2030, even with the capacity reserve activated.

**Regional margin minimum**

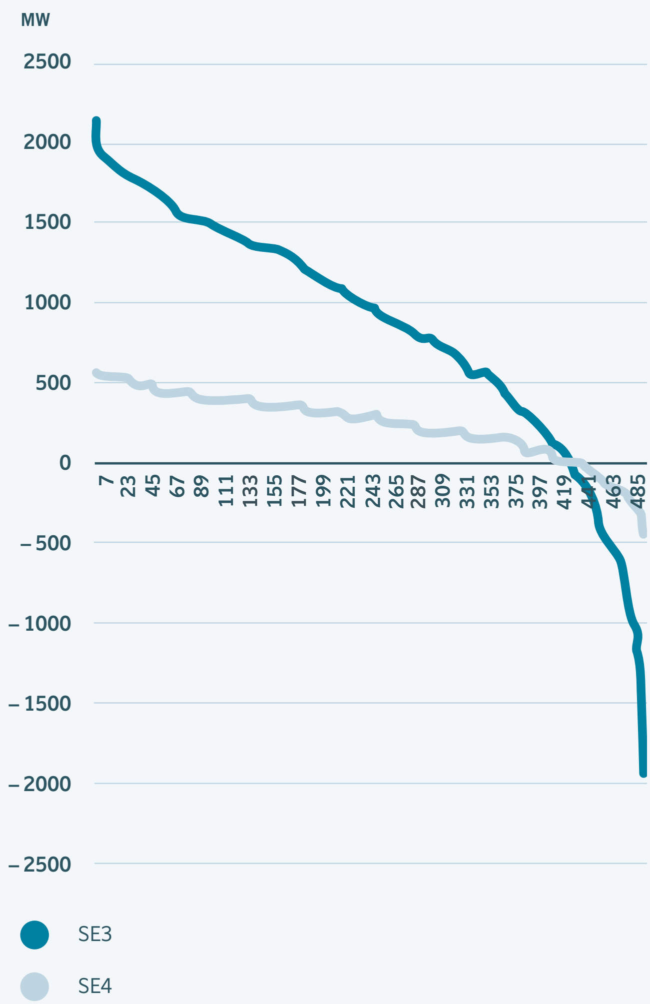


*Figure 12 Illustration of the minimum regional margin in each of the 500 simulations for bidding zones SE3 and SE4 in 2030. Here, 70 of 500 years have a negative value, which means that the spot market will not clear without additional measures.*

3

Generation adequacy

### 3.4 Challenge 3: Need for methodologies

#### 3.4.1 Probabilistic methodologies

A shared feature of all the studies is the complex nature of the various issues that can cause adequacy shortfalls. Shortfalls arise when a series of events occur such as cold winter spells combined with increasing numbers of faults with infrastructure or generation facilities. Consequently, it has to be acknowledged that no simple fixes exist, and that isolated mitigation measures are not capable of addressing all the shortfalls.

The methodology of the Danish, Swedish and one Finnish study is based on a probabilistic modelling approach (Monte Carlo), which models every hour of the year using historical weather and demand profiles. These are combined randomly with the stochastically simulated availability for interconnectors and power plants.

In 2014, ENTSO-E highlighted a need to improve the modelling of transmission management in times of scarcity. It decided to switch to a probabilistic analysis, which is more suited to an interconnected system characterised by variations in load and high penetration of variable generation. In 2015, ENTSO-E conducted a pilot phase study in order to define a framework for probabilistic market modelling adequacy assessments for the forthcoming Mid-Term Adequacy Forecast Report and subsequent developments in further reports. The overall principle adopted in the probabilistic studies was to simulate several years' operation of the power system on an hourly basis, with hourly profiles for wind and solar power and demand. It also includes the availability of thermal power plants and interconnectors (including both planned and forced outages). In the ENTSO-E pilot phase, outages for interconnectors were not included in the model; however, the forthcoming Mid-Term Adequacy Forecast Report will include some interconnectors.

Flexible production is simulated using a methodology in which each power station is assigned a risk of being unavailable (for example, due to a breakdown) in a given hour while international connections can drop out individually, or all connections to a neighbouring region can drop out at the same time due to inadequate power in the region.

Future analyses of adequacy should apply a new common methodology, including a probabilistic modelling perspective for all hours of the year, which enables a more consistent assessment of varia-

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# Generation adequacy

ble renewable energy generation, projected interconnector flows, demand-side management and flexibility in the market.

### 3.5 Solutions on generation adequacy

National analyses show an increased interdependency within the Nordic countries, between the Nordic countries and to the European Continent. This is due to the increasing number of interconnectors and a cross-border market. Cross-border dependency is most prevalent in Denmark and Finland.

Furthermore, the studies reveal an increasing level of expected energy not supplied due to decreasing capacity in the Nordic region. In the studies, Finland, southern Sweden and eastern Denmark face short-term adequacy challenges. Some of these can be solved through future planned transmission or production capacity. The overall trend is however towards a tighter capacity margin, which could influence the level of expected energy not supplied. Further studies in the form of a common Nordic project will be required to clarify future consequences.

The findings from various national studies and ENTSO-E's most recent adequacy assessment have given rise to a list of action points. Cross-border collaboration on adequacy is important. Transmission capacity is increasing, both within the Nordic system and between the Nordic and other systems. Furthermore, the Nordic countries reap certain benefits from sharing back-up capacity. The Nordic countries have a history of sharing capacity in the wholesale market, now it is time to harvest the benefits of sharing back-up capacity between countries.

Solutions through collaboration between the Nordic TSOs:

- **Continuing development of a common market – enabling consumers:** In the long-term, consumers are expected to play a more prominent role by expressing a willingness to pay for security of supply. A shared solution that fosters consumer flexibility and participation in the common market will improve the situation and force new and effective solutions. Consumer flexibility is however expected to make only a small contribution to adequacy over the shorter term due to the limited potential flexibility in some Nordic countries.
- **Common methodologies – probabilistic:** A probabilistic cross-border approach should be adopted for adequacy assessments, as this provides a more holistic assessment of potential capacity scarcities in the assessed region. More importantly, such an approach illustrates the potential support each country can receive or give through possible economic exchanges arising from the variety of generation mixes in the region.
- **Common study – from national adequacy to Nordic system adequacy:** Capacity issues have been predicted in Finland, eastern Denmark and southern Sweden. At the same time, Finland and Denmark are increasingly relying on imports. In order to analyse this issue more thoroughly, a common analysis is required from a Nordic perspective, and later also from a larger perspective. The study needs to include evaluations on situations that could lead to adequacy problems, and subsequently highlight opportunities for regional collaboration.
- **Collaboration on mitigation measures – common principles:** Some adequacy problems can be the result of common Nordic situations (e.g. cold winter spells combined with a dry year). However, this also means that mitigation measures can be developed through Nordic collaboration. Other adequacy problems can be local in nature. In such situations the affected countries have to identify national solutions. Here, the first step is to find common principles for mitigation measures that take account of the specific characteristics of the adequacy shortfall.

Overall, solutions to solve potential adequacy shortfalls cannot be solved by the TSOs alone. Some of the challenges will have to be addressed at a Nordic or European level. These issues include:

- **Aligned RES subsidies:** RES subsidies to be coordinated on the regional level.
- **Common definition:** Adequacy is a common Nordic challenge which will necessitate ongoing common market development and implementation of common adequacy assessments. In order to do this, the regulatory framework will have to adopt common definitions of generation adequacy.
- **Collaboration on the regulatory framework for both methodologies and mitigation measures:** Use of methodologies and mitigation measures are closely linked to the regulatory framework in both national member states and Europe. To fulfill the ambition of conducting common regional and European studies that can be used nationally, will require a common framework.

4

# Frequency quality

### 4.1 Ongoing changes in the power system will challenge frequency quality

The common frequency in the Nordic synchronous system means that imbalances affect the entire synchronous area. It is therefore important that the TSOs who are operating the same system adopt a shared view on target levels for frequency quality. Frequency is a crucial parameter when dimensioning reserves, and adequate frequency quality therefore indicates a sufficient level of security of supply. A common Nordic target for the frequency quality is currently being assessed as part of the new Nordic System Operation Agreement (SOA). This will be important for system operation in the period leading up to 2025, during which imbalances are expected to grow.

The main challenges with regard to maintaining an adequate frequency quality are:

- Larger structural intra-hour imbalances and more forecast errors.
- An increased need for, but reduced access to, reserve capacity.
- A growing need for transmission capacity for reserves.
- Changes around hour shift.

Over the next ten years, the Nordic power system will experience challenging situations with larger, faster and more frequent fluctuations. Major and rapid changes in the power flows via HVDC links and changes in wind generation will cause significant balancing difficulties. This will also affect bottleneck handling. Figure 13 shows simulated exchange via HVDC links during an average winter week in 2025, without and with the new planned interconnectors Nordlink, NSL and Hansa PowerBridge. The market simulations show large changes in power flow via HVDC links during mornings and evenings. The Nordic TSOs need to continue building a common toolbox to manage these imbalance challenges.

### 4.2 An increasingly challenging situation

System frequency is an indicator of the instantaneous power balance between production and consumption, including power exchange in the power system. Major frequency deviations indicate reduced system security. This implies an increased risk of disturbances that will lead to a frequency low enough to trigger automatic load-shedding, i.e. the last resort of system stability measures.

**Nordic exports and imports 2025, average winter week**

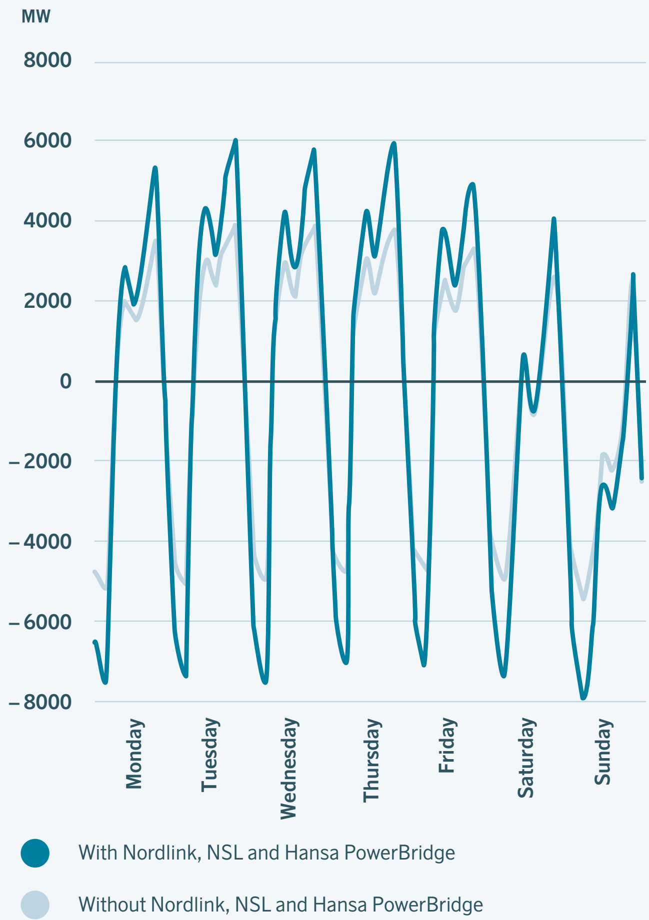


*Figure 13 Simulated exports and imports via HVDC connections from the Nordic synchronous system in 2025, without and with the new planned HVDC interconnectors Nordlink, NSL and Hansa PowerBridge. Simulated week in winter, per hour during week, average of 51 historic years. Ramping restrictions on the cables are not taken into account.*

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# Frequency quality

In the planning phase, well-functioning markets are important for a planend balancing between demand and supply contractually; however, imbalances will still occur in real-time system operation. System operators have various tools to manage imbalances, both administrative- and market-based. Adequate frequency and balancing reserves are critical for maintaining the real-time balance. Maintaining the frequency level at 50 ± 0.1 Hz at all times has proved increasingly difficult for system operators, see Figure 14.

Changes in the power system in the years leading up to 2025 will result in an additional deterioration of frequency quality if new and appropriate measures are not introduced. The trend towards more imbalances caused by power exchanges and shifts in generation will continue. The following challenges will amplify this trend:

- Faster, larger and more frequent changes in generation and power flow will further exacerbate real-time imbalances.
- A significantly higher proportion of the generation portfolio will be directly weather-dependent, as well as less predictable, less flexible and less controllable.
- New components with higher rated power, such as new power plants and interconnectors, could challenge system stability in the event of disconnection.
- Periods with few hydro power plants with reservoirs in operation, which makes it difficult to source a sufficient volume of frequency containment reserves and down-regulating resources.

## 4.3 Challenge 1: Larger structural intra-hour imbalances and more forecast errors

Major frequency deviations are likely to occur around hour shifts in the morning and in the evening, when there are large shifts in consumption, production and exchange on the HVDC links. Large intra-hour imbalances arise due to the differences between the ramps by which consumption, production and exchange achieve their hourly energy plans. The current marked design does not ensure momentary balance at intra-hour timeframes, even if all the balancing responsible parties are in balance per hour - so called structural imbalances.

The trend towards increasing intra-hour imbalances is expected to continue due to faster, larger and more frequent changes in generation and ramping on HVDC links. Efficient use of the HVDC links in the day-ahead and intra-day market requires faster changes in flow

### Development in Frequency Quality from 2001 to the first quarter of 2016

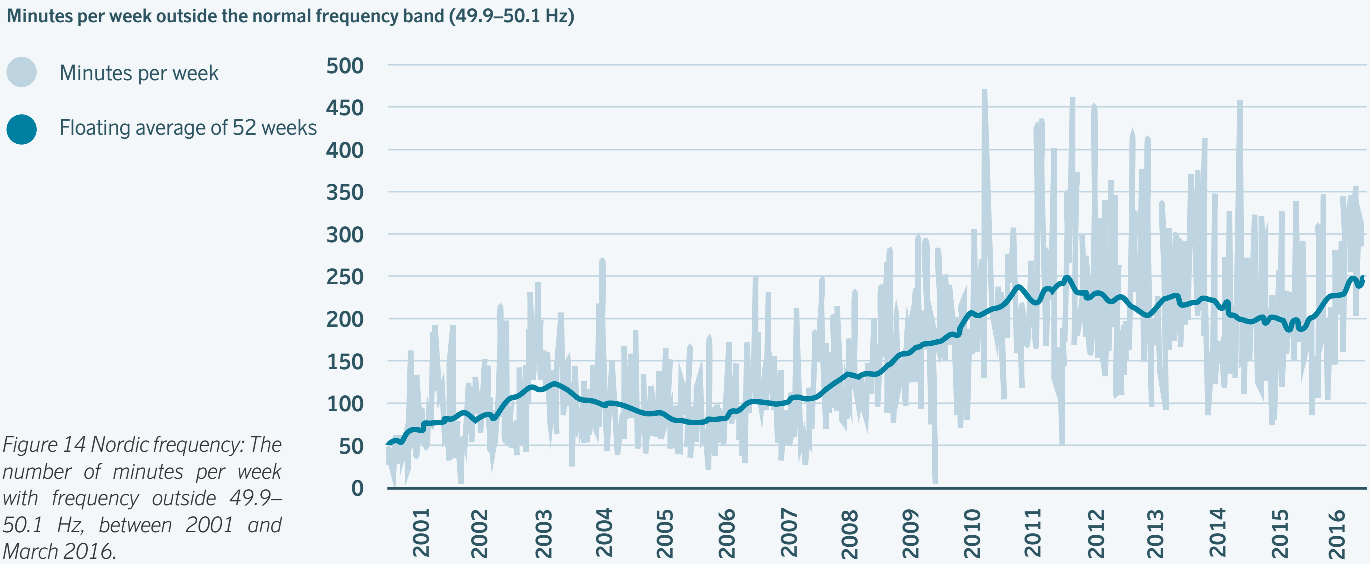


*Figure 14 Nordic frequency: The number of minutes per week with frequency outside 49.9–50.1 Hz, between 2001 and March 2016.*

direction than are currently accepted. This will further increase the intra-hour imbalances if mitigation measures are not introduced.

More unpredictable power generation in the Nordic system will increase of forecast errors. In addition, significant amounts of unpredictable power generation in the Continental European power system will cause large imbalances more often. With a tighter coupling of the two systems both physically and market-wise, the central European imbalances will permeate into the Nordic system through intra-day trade and balancing markets.

### 4.4 Challenge 2: Increased need for, but reduced access to reserve capacity

In future, the Nordic system will feature new components with higher rated power, such as new larger nuclear plants in Finland and larger HVDC interconnetors to neighbouring power systems. This will challenge system stability in the event of disconnection while larger dimensioning faults increase the need for reserves to recover. To some extent, power plants with lower rated power display different characteristics to traditional thermal and larger hydropower plants, due to differences in kinetic energy, regulation capability, and control functions. Often these smaller power plants do not provide frequency and balancing reserves.

When fewer large power plants are running, challenges with regard to reserve capacity arise, and the capability of the system to maintain a stable frequency deteriorates. Analyses from Statnett show that if the market has the same functions and products in 2025 as today, the market will not be able to secure an adequate level of inertia, frequency and balancing reserves, especially in summer periods. Figure 15 shows simulated Nordic production and load in 2025 for the night segment in a hydrologically normal year. The load in the summer period is mostly covered by must-run hydro[9], nuclear and wind power. The low production levels challenge both the availability of resources for frequency balancing and inertia.

**Nordic production and demand in 2025**
**For a typical single year (weather as 1982) and night hours**

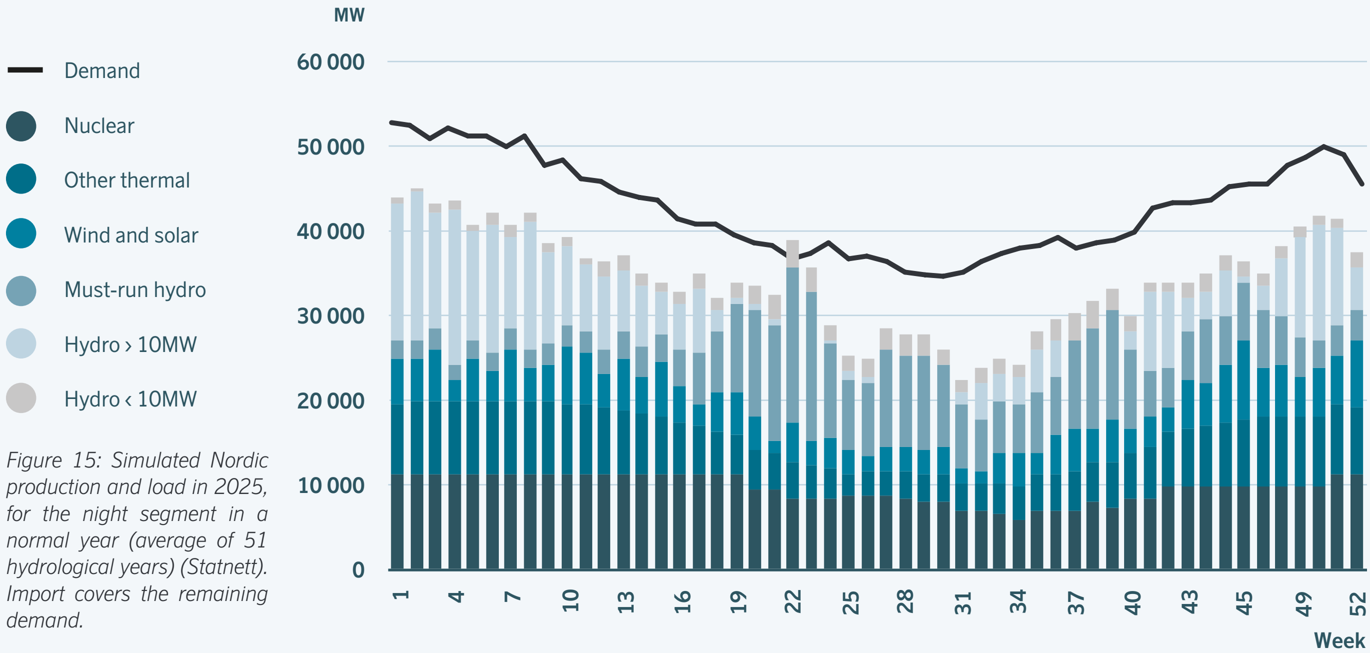


*Figure 15: Simulated Nordic production and load in 2025, for the night segment in a normal year (average of 51 hydrological years) (Statnett). Import covers the remaining demand.*

[9] *Must-run hydro: Production from power plants without reservoirs and power plants with reservoirs that are required to produce power at a specific time for various reasons, including full reservoirs, flow restrictions, reservoir targets etc. Includes all hydropower production with zero marginal costs.*

# 4

# Frequency quality

### 4.5 Challenge 3: The need to ensure adequate transmission capacity for reserves

Access to frequency and balancing reserves requires available transmission capacity. Effective management of congestions in the grid plays an important role in securing system operation and efficient use of resources. From a physical point of view, reserves should be distributed in such way that the requisite up- and down-regulation resources will be available for surplus or deficit areas. The costs of reserves and transmission capacity vary between areas and over time, meaning that the distribution of reserves has to be dynamically optimised to ensure that necessary grid capacity is available for the reserves. This would reduce costs compared to having a fixed distribution of reserves over time.

One current challenge relates to geographically unbalanced volumes of primary reserves (FCR) in the synchronous system. Another challenge involves a lack of Regulation Power Market (RPM) bids in the multinational deficit area in the south (NO1, SE3, SE4 and DK2) on cold days, and in particular when temperatures drop and there is a significant risk of market shortages. Such situations often result in congestions from west to east in Norway and from north to south in Sweden. This creates a risk that reserves earmarked for disturbances have to be used for Nordic imbalances. This would lead to unacceptable system security.

### 4.6 Solutions for reducing and handling imbalances

- **Higher time resolution in energy and balancing markets**

Intra-hour structural imbalances are predictable and should be more extensively handled in the planning phase through the power markets. Higher time resolution in energy and balancing markets, along with appropriate incentives for the balance responsible parties will secure a better planned power balance at the sub-hour timeframe and then result in a significant reduction in intra-hour imbalances. This will improve frequency quality and security of supply. It will also reduce the demand for frequency and balancing reserves.

Higher time resolution will also provide new market opportunities for consumers and producers, facilitate increased grid utilisa-

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# Frequency quality

tion and improve the accuracy and effectiveness of incentives for market participants.

An ongoing joint Nordic project is currently examining options to implement more finely tuned time resolution in the Nordic system, i.e. in the energy market, the balancing market and settlement. Important main drivers for the project are existing/new system challenges and regulations in the upcoming Network codes. The project shall within April 2017 work out a recommendation to implementation concept and submit this to the Nordic Market Steering Group (MSG) for further decision.

- **Securing adequate frequency and balancing reserves**

To secure frequency quality, it will also be crucial to adjust the current mechanisms to meet new challenges. As markets may not be able to secure adequate inertia, frequency and balancing reserves in all future periods, it will become more important to secure reserves before the day-ahead market. New solutions for securing an adequate level of inertia should be considered in the context of frequency containment reserves (FCR).

The Nordic TSOs are currently developing a common market for automatic frequency restoration reserves (aFRR). A number of other Nordic projects intended to further develop and improve frequency containment reserves are also underway. To date, aFRR have been procured separately by each country based on a national distribution of the total Nordic need. The aim is to achieve more efficient socio-economic solutions while taking into account operational distribution requirements. The Nordic TSOs have agreed on a system for market-based reservation of transmission capacity, which will involve capacity being allocated to the market where it is expected to have the greatest value. To this end, as a first step Statnett and Svenska kraftnät have run a bilateral pilot project on transmission capacity allocation for exchange of aFRR.

Adequate solutions have been developed to allocate transmission capacity to the reserve markets. In theory, an optimal solution would be to clear all reserve markets and the electricity spot market simultaneously, where the allocation of transmission capacity between the various markets is part of the optimisation

## Illustration of how a quarter-hour market reduces structural imbalances

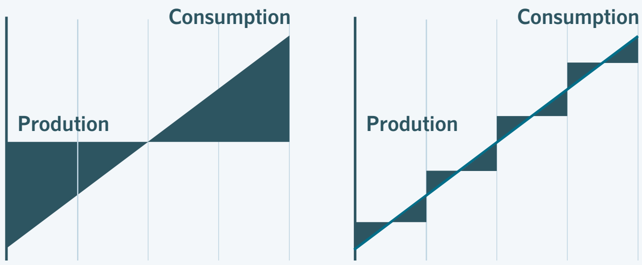



*Figure 16: Illustration of how a quarter-hour market with production changes in quarterly steps reduces imbalances. In the figure on the left, which represents an hourly market, the production plans remain constant throughout the hour and ramp at hour shift while consumption changes during the hour remain at a constant rate. In the figure on the right, production changes in four steps, here representing a quarter-hour market, and both the instantaneous power balance (vertical) and the imbalance energy (the blue area) decrease significantly.*

algorithm. However, this is a long-term objective. Over the short term, the aim should be to introduce more effective coordination of reserve procurement, including more efficient allocation of transmission capacity to the reserve markets. The solutions for exchanging reserves will have to be further developed and coordinated in the Nordic countries in order to allow reserves to be shared and exchanged within and outside the synchronous area.

From a longer-term perspective, current or potential future location of reserves, and in particular affordable reserves, should be considered in any analysis of potential grid reinforcements.

Accurate price signals play an important role in securing long-term incentives for market stakeholders to invest in functionality to serve adequate frequency and balancing reserves. The market structure, including more products for balancing and integration of more areas, should be evaluated with respect to the pricing of imbalances.

Reserves also need to be procured from new sources. The implementation of the third package by the European Commission, including network codes, will lead to changes in roles, rules, methods, cooperation and products in the reserve markets. These changes will to some extent help to pave the way for new suppliers. Below are some foreseen developments:

- Standard products will also facilitate new suppliers, including for demand-side and small-scale resources.
- The introduction of a new role in the Nordic area, Balance Service Provider, will enable the market to submit reserves to TSO.
- Extended cooperation in balancing (outside the Nordic system) will secure better utilisation of reserves and could increase the reserves available for balancing.

The implementation of AMS with two-way communication could enable accurate metering of electricity consumption with finer time resolution and allow electricity consumers to receive price information and thereby send more dynamic price signals to end-users.

The solutions for and access to reserves will be more flexible in future markets. It will be vital to secure an adequate amount of reserves for the day-ahead market. The most efficient socio-economic approach would be to complete trading of reserves shortly before closure of the day-ahead market on a daily basis.

- **Utilisation of market harmonisation and joint/coordinated ICT solutions**

There is currently a major focus in the Nordic region on further market harmonisation. This is being driven by both the operational needs of the Nordic TSOs and the implementation of common European network codes. The Nordic TSOs currently employ a joint planning system for manual balancing (NOIS) but it needs to be improved. During 2016, a new company eSett, which will introduce a new ICT system, will assume operational responsibility for imbalance settlement and invoicing for Finland, Norway and Sweden.

Several joint R&D initiatives using advanced technology are currently being piloted as part of the Nordic TSOs' long-term development plans. One key initiative involves the deployment and use of synchro-phasor technology (called PMUs – phasor measurement units). PMUs will contribute more real-time information that will be useful for system operators.

- **Leveraging of new technologies in system operation**

Advanced systems that provide better supervision and real-time control, and more automation of operational processes will be required to handle increased complexity and risk in the power system moving forward. In future it will be necessary to make even faster decisions in system operation, which will make it crucial to have adequate real-time information. Control centres and operating systems will have to process high volumes of increasingly complex system data. As the power system develops into a more online and real-time system, the control centres will be the main hub for monitoring, planning, and control actions. The national control centres will have to have access to operational information on the status of both the national and Nordic systems, and related preventive and corrective control actions. This will require more real-time analyses.

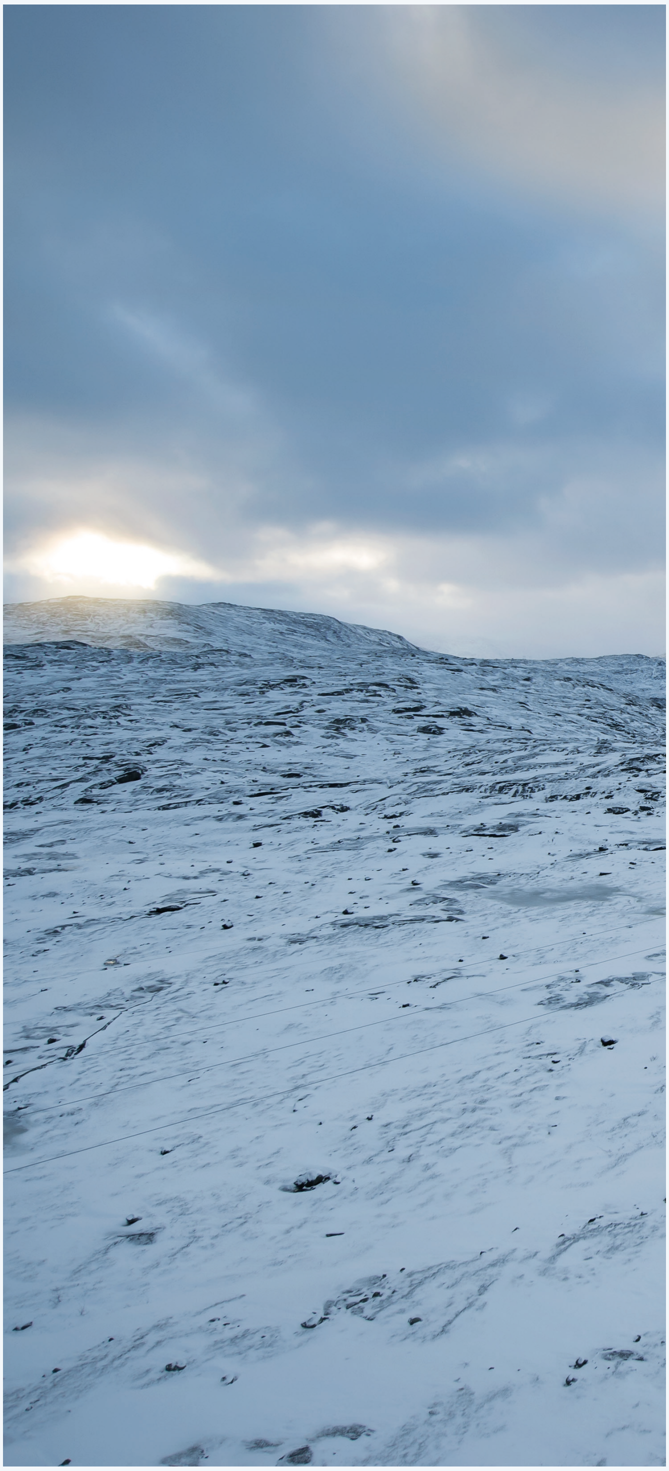
Additional automatic and responsive control systems will be required in the future. To increase system observability, the algorithms for bid selection in reserve markets will have to be optimised, including for congestion management and electronic activation of bids. The embedding of power grid and ICT systems will improve the efficiency of network operations, and will also facilitate more timely and precise knowledge and information about the status of the system, which in turn will help to reduce the consequences of failures and frequency deviations.

### 4.7 Increasing value through cooperation and joint solutions

Further market and operational development will have to take place within the framework of joint European legislation, including the European network codes, as well as through close collaboration between the Nordic TSOs. With more interconnectors linking other areas, greater impact from these areas is likely. Nordic market solutions will need to be harmonised and preparations made for efficient integration with European markets.

The Nordic TSOs will establish a Regional Security Cooperation Service Provider (RSC) from 2017. This will comply with EU regulations on capacity calculation and congestion management (CACM network code) and system operation (EC 2015), both of which are already in force. The Nordic RSC is a joint office set up by the TSOs to provide services to the TSOs relating to the common grid model, capacity calculation, security analysis, outage coordination and short-term adequacy analysis. The national TSOs will remain in charge of security of supply and final operating decisions.

The current focus in European legislation on boosting regional cooperation in balancing represents a first step on the road to a pan-European balancing market. The tools used for regional cooperation on netting and frequency restoration reserves in Europe are “Coordinated Balancing Areas” (CoBAs). While the Nordic TSOs already cooperate, further harmonisation and formalisation of the legislative framework is required. The Nordic TSOs have announced that they will form a Nordic CoBA for manual frequency restoration reserves (mFRR).



# 5 Inertia

## 5.1 Introduction

Inertia is defined as the resistance of a physical object to change its state of motion. In a power system, inertia mostly derives from synchronous generators and turbines at conventional power stations, where the motion is the rotational speed of the synchronous generator rotors (Tielens & Van Hertem 2016.) The rotating speed of the generators corresponds to the system frequency. In a power system, inertia refers to the resistance of the system to change its frequency after an incident. When the generation-consumption balance changes after generation or load variations, the frequency always changes too.

A significant imbalance occurs, for example, when a generator with a high volume of generated power is disconnected from the system. The mechanical rotating speeds of turbine-generator rotors decelerate, which releases kinetic energy from the rotors into the power system. The frequency then starts to decrease. In this way, the connected generators will compensate for the imbalance caused by the disconnected generator; however, the generators' immediate rotating speed, and hence the power system frequency, decrease.

Reserves regulate their power according to the frequency and help to keep the frequency near the nominal value. If the frequency becomes too low after a disturbance, loads are shed in progressive steps in order to boost the frequency and to keep the system operational. If load-shedding does not help and the frequency decreases too much, the generators are disconnected from the system and a blackout occurs.

Inertia in a power system and the rate of change of frequency (RoCoF) are interrelated. Large amounts of inertia in the system reduce the rate of change of frequency. Power system inertia mainly derives from the kinetic energy stored in the rotors of turbine generators, (Ulbig, Borsche & Andersson 2015), which then provide kinetic energy to the grid or absorb it from the grid when the frequency changes. With high inertia, the frequency decrease is slower and the frequency containment reserves (FCR) have more time to react and increase the frequency back towards the nominal value. Figure 17a shows how the amount of inertia affects the frequency response after a generator trip. Figure 17b shows the power responses from inertia, reserves and load.

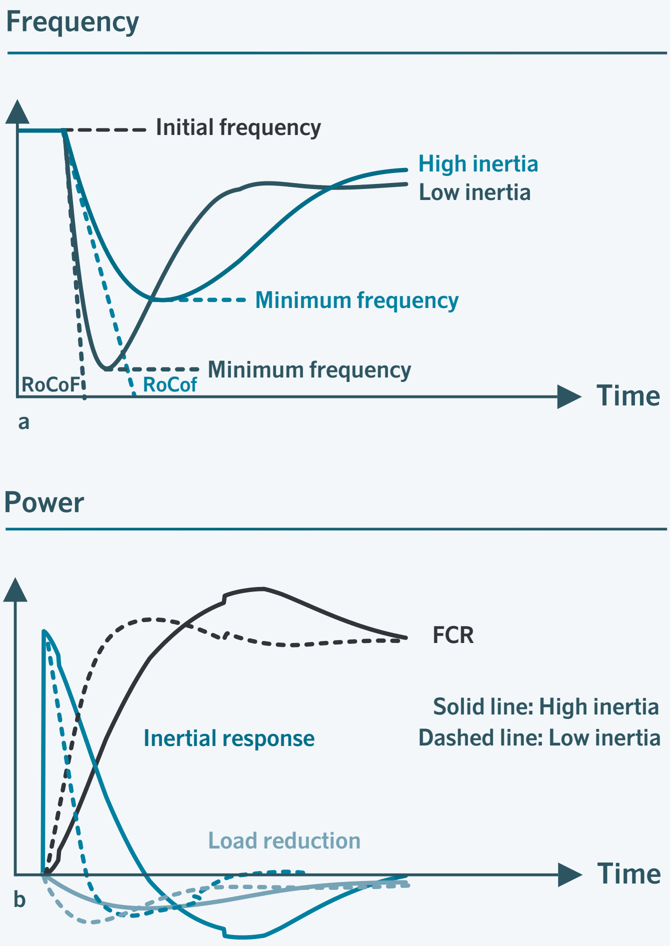



*Figure 17 Frequency and power responses after a generator trip. a) Initial frequency and frequency responses after a generator trip with high and low inertia and the corresponding RoCoF values. b) Power responses from kinetic energy (inertial response), FCR and load reduction.*

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# Inertia

With too low inertia, the frequency drop can be too fast, with the result that the frequency reaches the load-shedding value before the reserves have reacted sufficiently.

Larger amounts of renewable energy, phasing out of nuclear units and higher imports through HVDC connections all reduce inertia and kinetic energy levels. This may jeopardise system security after a large unit trip. The Nordic TSOs' joint project the 'Future System Inertia' report address many of these issues (ENTSO-E 2015b). The next phase of the project is intended to anticipate, avoid and mitigate low system kinetic energy situations by estimating future kinetic energy levels, developing measures to handle low inertia situations and improving inertia estimation tools.

In the following sections the adequacy of inertia during the target year (2025) is evaluated, along with the sensitivity of the assessments. Potential remedial actions are also reviewed. The scope of the study only covers the minimum frequency after the tripping of the largest unit (generator or HVDC link importing power) since the minimum frequency depends on the amount of inertia. Certain other aspects relating to low inertia, such as transient stability and frequency peak following the disconnection of a power-exporting HVDC link are not in the scope of the report.

## 5.2 Methodology

There is currently no requirement for minimum system inertia. However, the frequency after a dimensioning incident should be maintained above a specified value in order to avoid any load-shedding steps. In this analysis, it is assumed that the frequency has to be maintained above 49.0 Hz after any incident in order to maintain a margin from the highest load-shedding step, 48.8 Hz (ENTSO-E 2015a).

To maintain the frequency above 49.0 Hz, the system must have a sufficient amount of kinetic energy. However, inertia is not the only factor that affects the minimum frequency. There are four main factors: the size of the disturbance, the amount of inertia, the load self-regulation and the amount and behaviour of the FCR reserves, including the HVDC emergency power control (EPC) in the

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# Inertia

system at the time of the incident. However, in all cases, the inertia sets the initial rate of change of frequency for any given incident.

To gain an overview of the likely inertia situation during the target year, the hourly kinetic energy is estimated based on power productions from the market simulation scenario for 2025 described in chapter 1.4, and average inertia constants (ENTSO-E 2015b) of the various types of production in different bidding zones. The market simulations are carried out using all the measured historical data (e.g. inflows and temperatures) for all climate years between 1962 and 2012.

Disturbance simulations are carried out to gain an overview of how much kinetic energy is needed to withstand the tripping of the largest unit. The methods used to estimate kinetic energy and simulate disturbances are discussed in more detail in Appendix 2: Inertia. Figure 17 shows two examples of disturbance simulations.

### 5.3 Available and required amount of kinetic energy

The duration of available total kinetic energy and kinetic energy per production type is presented in Figure 18. The significance of the future challenges relating to inertia is established by comparing estimated kinetic energy with the required kinetic energy under various assumptions. The sensitivity of the assumptions is discussed in Appendix 2: Inertia.

The effect of total load, wind and solar production and HVDC imports on the amount of kinetic energy is presented in Figure 19. The figure shows the estimated hourly kinetic energy for all the climate years (1962–2012) used in the market simulation scenario. The lowest kinetic energy values are observed during summer nights when the load is low, see Figure 20. If the sum of wind and solar power and HVDC imports is high, kinetic energy can be low even with higher load levels; see Figure 19. The required amount of kinetic energy is dependent on the amount of load in the synchronous area, where the requirement is shown by the red line in Figure 19. The requirement line is based on the disturbance simulations described in the Appendix assuming 0.75%/Hz for load frequency dependence, so that the initial frequency is 49.9 Hz and

**Total kinetic energy and kinetic energy per production type**

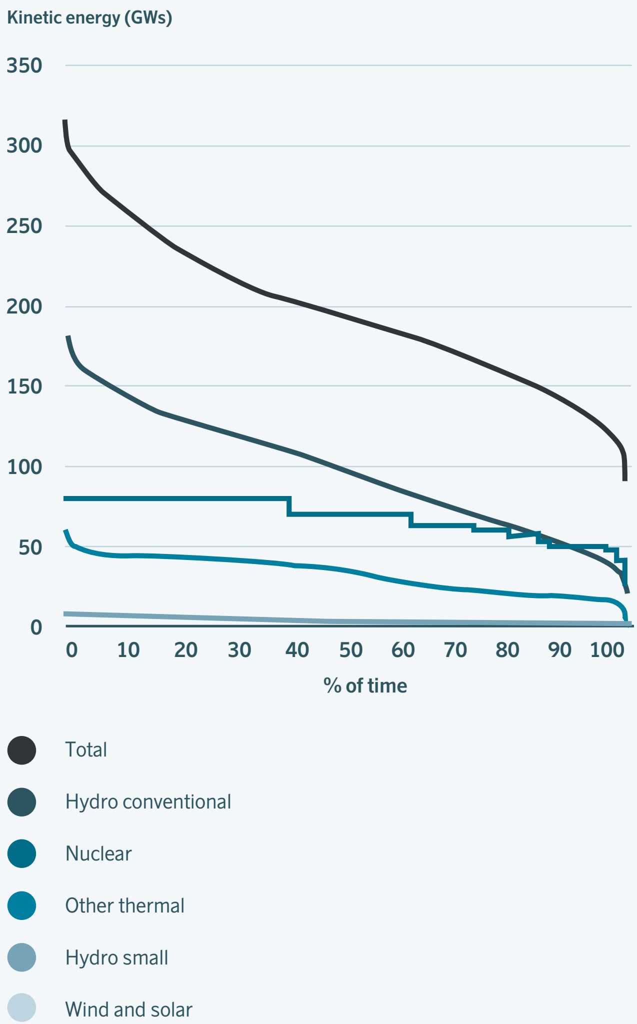


*Figure 18 Duration of estimated total kinetic energy and kinetic energy per production type in 2025. The curves are calculated based on all climate years (1962–2012) in the market simulation scenario.*

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# Inertia

the minimum frequency is 49.0 Hz after the tripping of the largest unit (Oskarshamn 3).

The kinetic energy in the system varies on a seasonal (Figure 20), and daily and weekly (Figure 21) basis. The lowest kinetic energy values are observed during summer nights.

### Estimated kinetic energy in 2025 as a function of total load

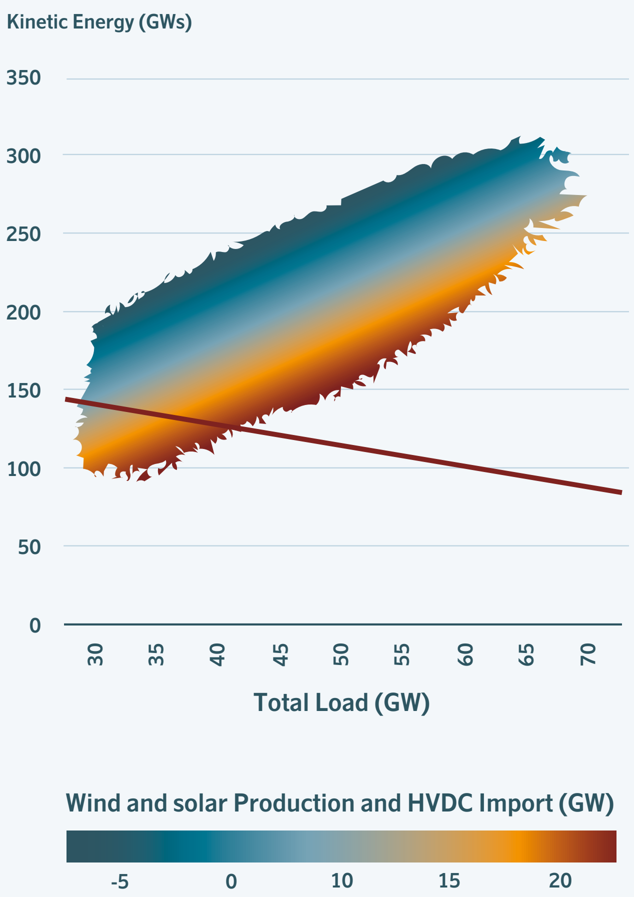


*Figure 19 Estimated kinetic energy in 2025 as a function of total load in the synchronous area with wind and solar production and HVDC import including all climate years (1962–2012). The red line shows the required amount of kinetic energy when 0.75 %/Hz is assumed for load frequency dependence (other assumptions in Appendix 2).*

### Estimated kinetic energy as a function of time in 2025

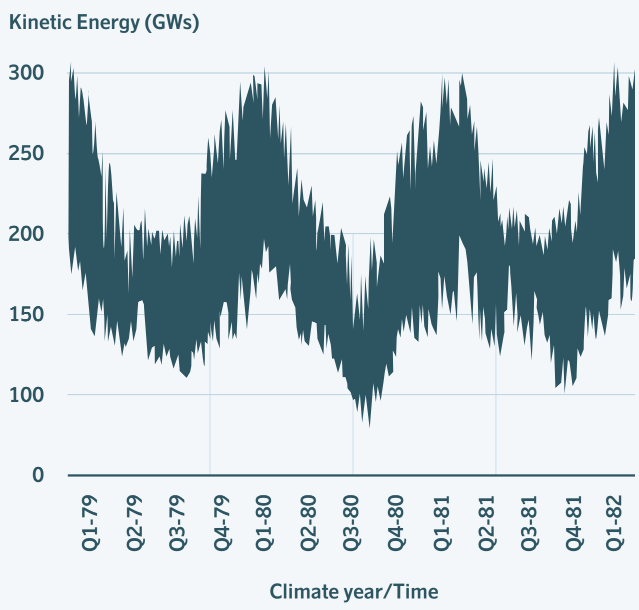


*Figure 20 Estimated kinetic energy as a function of time in 2025. The figure shows variation of the kinetic energy during three climate years (1979–1981).*

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# Inertia

## Daily and weekly variations of the kinetic energy

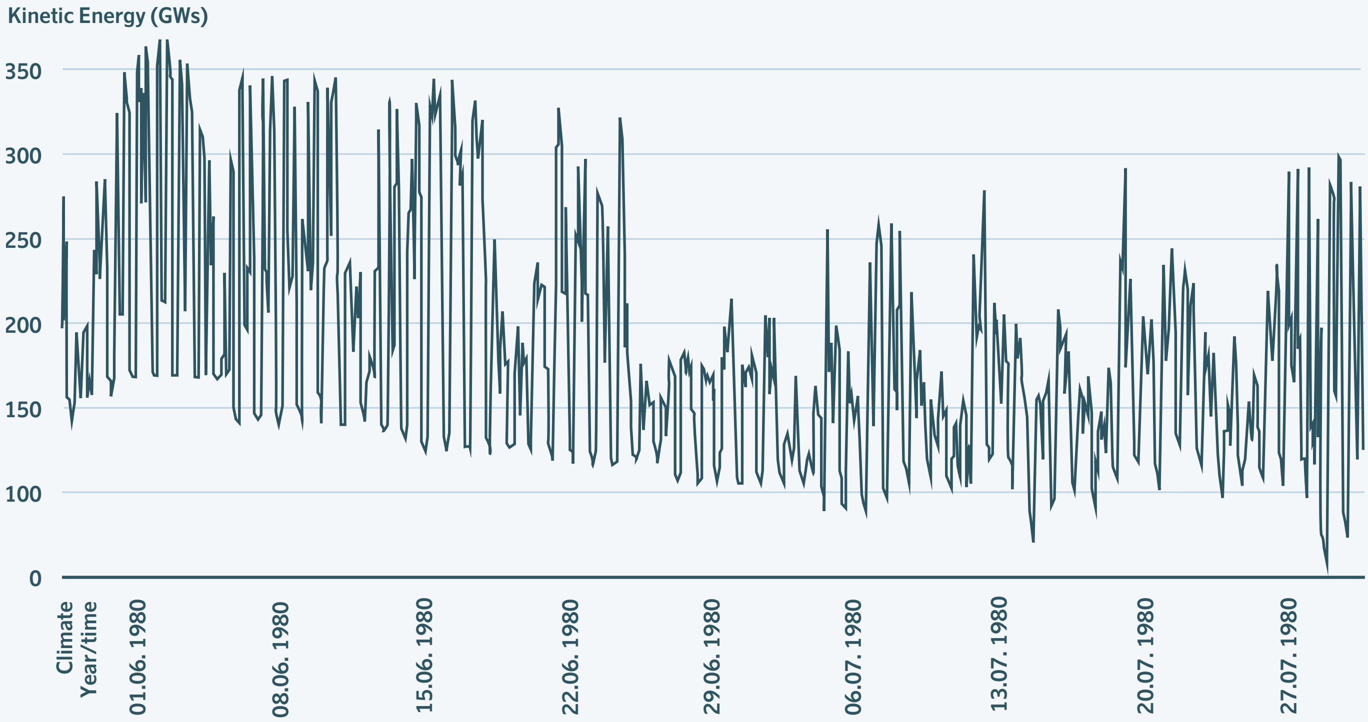


*Figure 21 Estimated kinetic energy as a function of time in 2025. The figure shows the daily and weekly variation of the kinetic energy during a period of two months in the summer of a climate year (1980).*

### 5.4 Adequacy of inertia

According to the Future System Inertia report, the kinetic energy capacity in the Nordic power system was about 390 GWs in 2015. In the period 2009–2015, the estimated annual minimum kinetic values ranged between 110 and 130 GWs while the corresponding annual maximum values varied from 260–270 GWs. In the period 2010–2015, the estimated kinetic energy was below 140 GW for 4 per cent of the time or less; however, in 2009 this duration was as high as 12 per cent (ENTSO-E 2015b).

In 2025 the inertia, measured as kinetic energy, is estimated to be below the required volume of 120-145 GWs between 1 and 19 per cent of the time, the average being 8 per cent (based on analyses with historical reference period 1962-2012) which is shown by the red line in Figure 19. Table 3 presents the basic statistical properties of the estimated kinetic energy.

| | All climate years | Dry year (1969) | Wet year (2000) |
|---|---|---|---|
| Kinetic energy (GWs) min. | 83 | 86 | 117 |
| Kinetic energy (GWs) max. | 315 | 305 | 304 |
| Kinetic energy (GWs) mean | 194 | 176 | 210 |
| Kinetic energy (GWs) median | 191 | 170 | 204 |

*Table 3 Statistical information of the estimated kinetic energy values for 2025 for all climate years (1962–2012), and for a dry year and a wet year.*

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The duration of total kinetic energy for all the climate years, and for a wet and a dry year, is presented in Figure 22. By comparing the values with the required amount of kinetic energy (applying different assumptions) we can assess the significance of future inertia challenges caused by low kinetic energy values on an average basis for all the climate years, and for a dry and wet year. Figure 22 shows that the climate year has a large impact on inertia challenges, with the dry year presenting the most difficult situation. When there is less hydropower available, it is mainly replaced with more HVDC imports, leading to lower inertia levels.

### 5.5 Sensitivity analyses

The sensitivities of kinetic energy calculations with respect to several parameters are presented in Appendix 2. The most important factors here are disconnected power, initial frequency, minimum acceptable frequency after the trip, load self-regulation and the amount and behaviour (mainly speed) of reserves. The amount of nuclear production during the target year of 2025 naturally has a significant impact on the amount of kinetic energy and the percentage of time the kinetic energy is expected to be below the required amount (if no preventive actions are carried out).

### 5.6 Possible solutions for low inertia situations

There are several methods of handling situations with low inertia, as far as the minimum frequency after the tripping of the largest unit is concerned. The need for inertia varies in different situations; however, the TSOs should ensure that the frequency does not drop below 49.0 Hz after the tripping of the largest unit. The methods for securing a sufficient amount of inertia can be split into legislative, market and the TSOs' own measures. Since not all measures are controlled by the TSOs, cooperation with other stakeholders is important. There are many options and the TSOs need to value each option and agree on the best solutions.

#### 5.6.1 Short-term Options

The short-term options refer to methods that do not require any new investments in the system, but which use existing reserves, tools, and

**Duration of total kinetic energy**

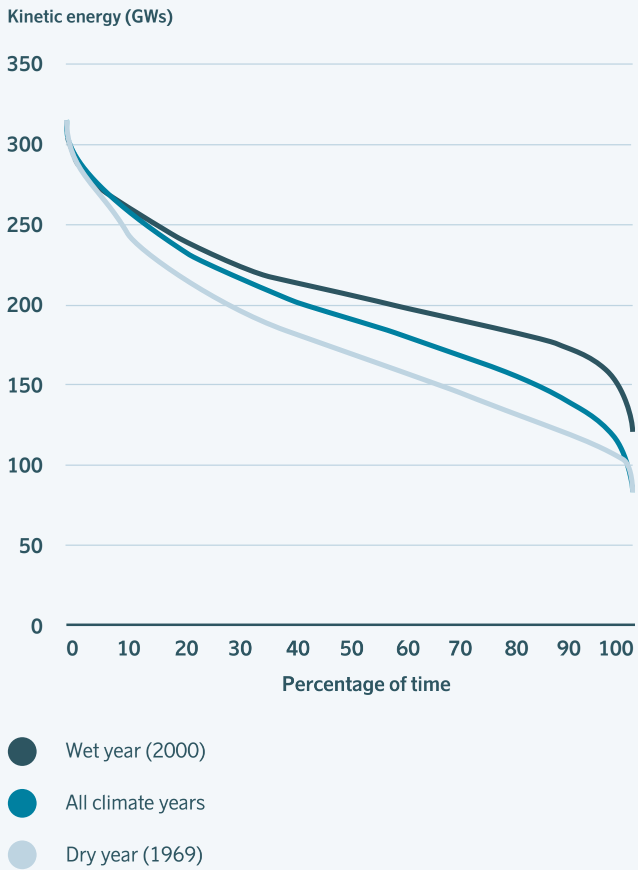


*Figure 22 Duration of estimated total kinetic energy for all the climate years (1962–2012), for a dry year and a wet year in the market simulation scenario in 2025.*

markets, including procuring larger amounts of reserves. In the short-term, the TSOs need to be aware of the real-time kinetic energy situation and the corresponding minimum frequency after the tripping of the largest unit since the required measures depend on the current situation. Although a tool for real-time estimation of the system kinetic energy has already been developed, further development opportunities exist in this area.

In the short-term, it will be possible to boost inertia in the system by running existing production units with lower average power output or to limit the power output of the largest units (generators and HVDC links) to a level where the frequency remains inside the permitted limits. Each synchronised unit adds to the total inertia regardless of its power output. Running more units is not efficient and requires market measures to offer compensation to plants that add inertia, which must be considered together with the need for frequency containment reserves (FCR).

Limiting wind power production and replacing this with other types of generation (with inertia) is also an option in terms of adding inertia to the system in the short-term.

### 5.6.2 Long-term Options

Long-term options require investments in the system, legislative actions or market measures.

More inertia can be added into the system by installing rotating masses, such as synchronous condensers. Establishing inertia markets or setting minimum system requirements for kinetic energy could also be options for securing sufficient levels of inertia.

Synthetic inertia (sometimes called virtual inertia) refers, for example, to the modulation of the power output of the power converters in wind power plants, HVDC links to outside the synchronous area and battery systems, in such a way that their output behaves in a somewhat similar manner to the synchronous machines after frequency variations. Adding synthetic inertia is an important option in terms of securing sufficient inertia in the future. Once the network code on requirements for the grid connection of generators becomes effective, it is for the TSOs to decide whether synthetic inertia will be required. (EC, 2016)

Over the long-term, other means include installing system protection schemes. For example, the maximum effective disconnected power can be limited by installing system protection schemes that, for instance, disconnect load in case it is needed.

It is also possible to add more FCR, including HVDC EPC, in the system, or potentially to increase the reaction speed of the reserves in the event of a disturbance. Both of these measures help in low inertia situations. It may also be possible to use more loads as reserves.

# 6

# Transmission adequacy

## 6.1 Introduction

### 6.1.1 Definition of transmission adequacy

Transmission capacity plays an important role in meeting the system challenges described in the previous chapters. Adequate transmission capacity facilitates cost-effective utilisation of energy production, balancing and inertia resources and helps to guarantee security of supply.

An adequate level of transmission capacity is reached when the benefits of further capacity investments are less than the associated costs. This definition means that there will occasionally be periods of congestion and price differences between bidding zones. Similarly, an adequate level of transmission capacity cannot be expected to completely rule out a risk of loss of load in areas with a strained power balance. The key to transmission system planning is to balance costs and benefits with regard to the risks.

This chapter discusses the challenges that lie ahead with regard to creating an adequate future-proof transmission system.

### 6.1.2 Nordic transmission adequacy today

The Nordic transmission grid is well developed compared to European systems. Thanks to a well-integrated electricity market with marginal disturbance to cross-border trade, the Nordic countries achieved the European Energy Union's target of 10 per cent interconnection capacity between countries (in relation to national production capacity) some time ago. Figure 23 shows the transmission capacities between bidding zones in the Nordic and Baltic power systems.

**Nordic and Baltic power system**

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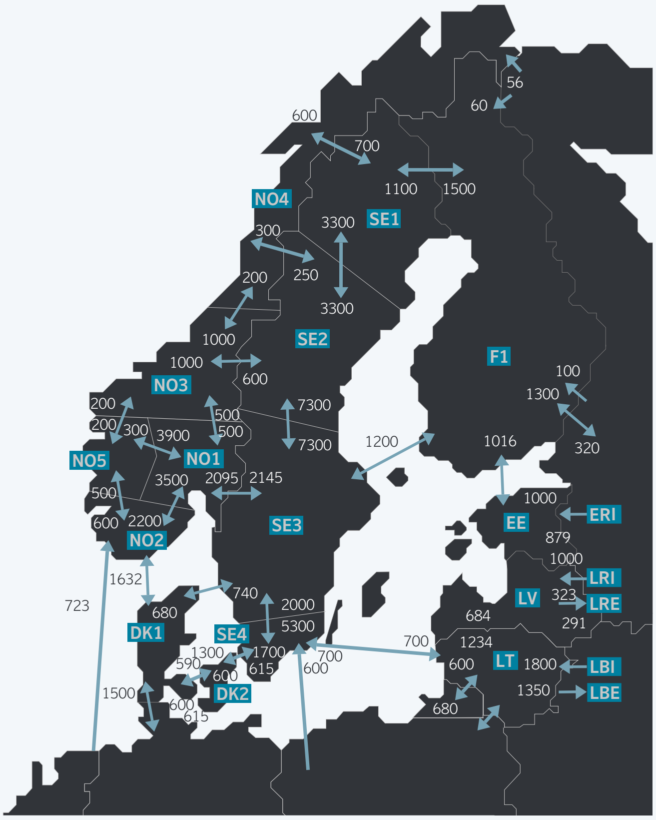


*Figure 23 The Nordic and Baltic power systems with transmission capacities (maximum net transfer capacities of March 2016 (Nord Pool 2016a).*

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# Transmission adequacy

Congested interconnectors within the Nordic transmission system result in recurrent price differences between bidding zones. Figure 24 shows the number of congested hours (hours with a price difference) between the Nordic bidding zones in the period 2013–2015. Several connections have been congested for more than 4,000 hours per year, or close to 50 per cent of the time over the past three years.

## Number of congested hours between Nordic bidding zones

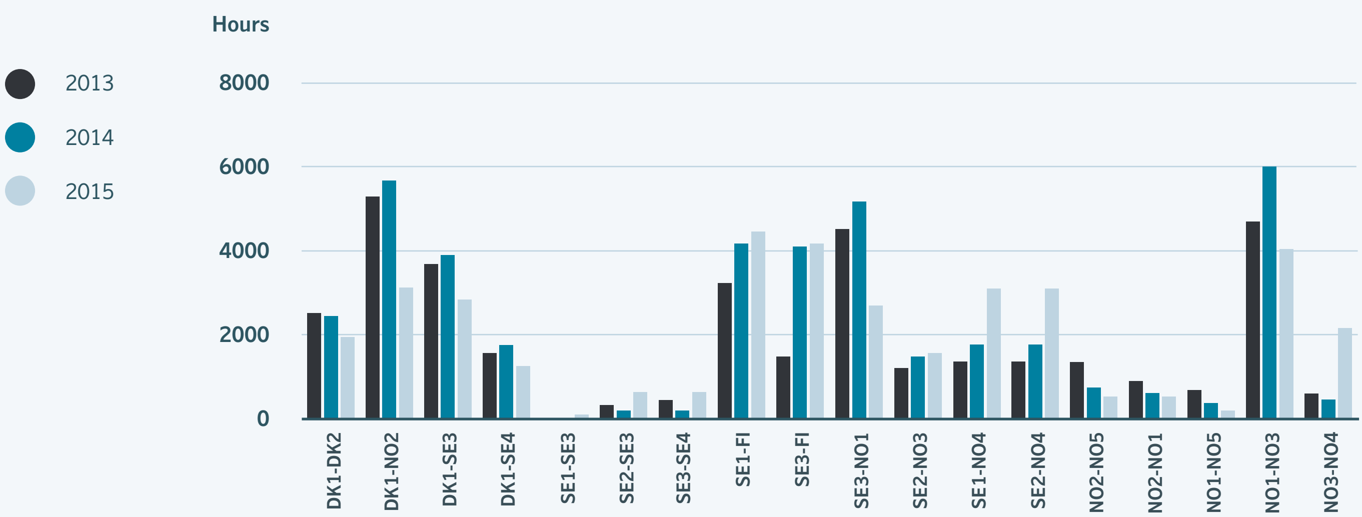


*Figure 24 Number of congested hours (hours with a price difference) per year between the Nordic bidding zones during 2013–2015 (Nord Pool 2016b).*

# 6

# Transmission adequacy

To understand the magnitude of the bottlenecks it is also necessary to consider resulting price differences and existing transmission capacity. The congestion rent for an interconnector reflects both these factors, as it is the product of power flow and price differences for a certain period of time. The number of congested hours and the related price differences typically depend on weather variations, changes in generation capacity and buildout of new transmission capacity. Figure 25 shows that congestions in connections between Sweden and Finland have resulted in large congestion rents over the last two years, partly due to a wet 2015 with large amounts of low-cost hydro power and structural production deficits.

### 6.1.3 Transmission planning

Each TSO in the Nordic region is responsible for developing the transmission system within its borders. The Nordic TSOs have

## Congestion rent between Nordic bidding zones

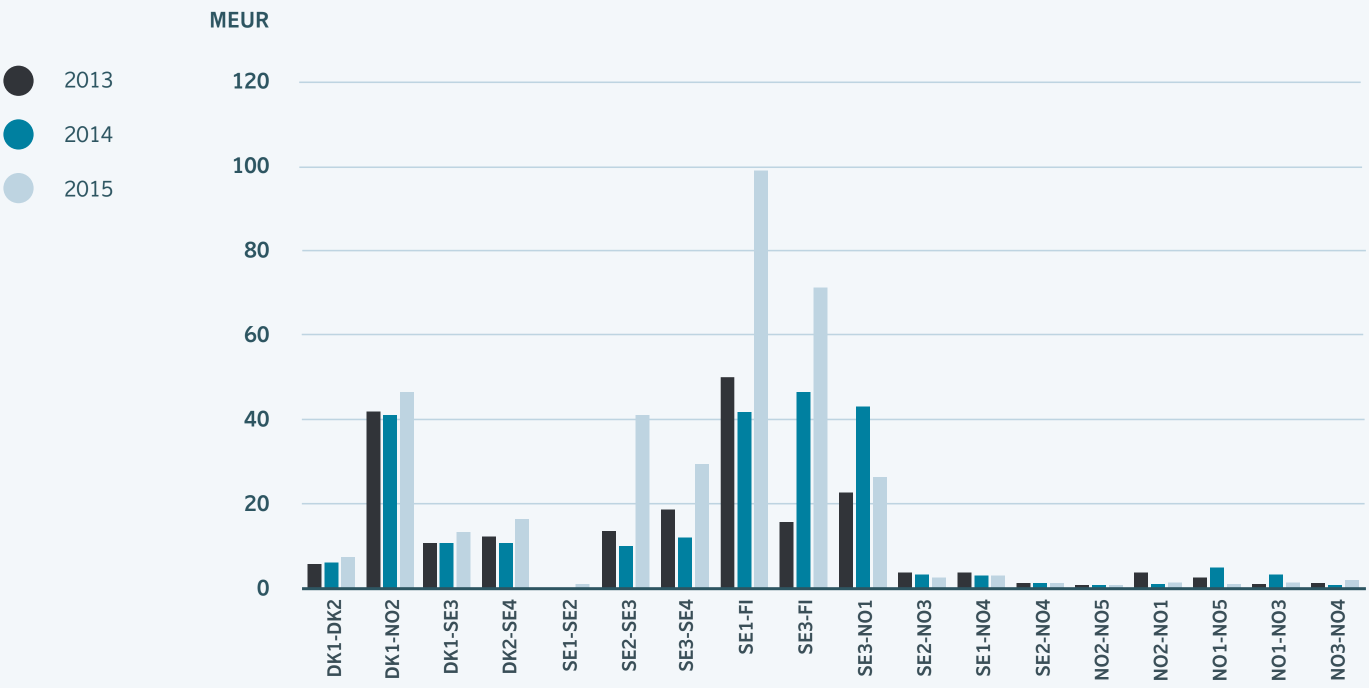


*Figure 25 Congestion rents between Nordic bidding zones for 2013–2015 (Nord Pool 2016b).*

# 6

# Transmission adequacy

published national grid development plans that present both approved projects and project candidates. The very nature of the transmission system makes regional cooperation essential to achieving an effective power system. This has been fully acknowledged by the Nordic TSOs, and joint grid development plans have been published since 2002. Within the framework of the Ten Year Network Development Plan (TYNDP), regional plans for the Nordic and Baltic countries are published every two years.

Several investment projects intended to address the current bottlenecks are in the planning phase or under construction. The SouthWest Link between SE3 and SE4 is planned to be commissioned during 2016 and 2017. Reinforcement of the grid on the Swedish west coast will lead to fewer capacity reductions in the Hasle section as well as between Sweden and Denmark while reinforcements in southern Norway will also contribute to less congestion between NO1 and SE3. In August 2016, Svenska kraftnät and Fingrid will conclude a bilateral study on increased capacity between Finland and Sweden. Reinforcement of north-south capacity is planned or ongoing in both Norway, Sweden and Finland.

The regulatory framework is different in each of the Nordic countries, and the exact formulations of objectives vary between the TSOs. There is, however, a common understanding that the transmission system should enable an effective power system with a high degree of security of supply and facilitate integration of renewable power production and an increased integration of markets.

### 6.1.4 Regional investment plans 2015

ENTSO-E is structured into six regional groups for grid planning and other system development tasks. All the Nordic countries except Iceland are members of the Baltic Sea Regional Group, and Denmark and Norway are also part of the North Sea region. These regional groups publish biennial Regional Investment Plans. A number of drivers were identified for regional transmission planning in the Baltic Sea region, as shown in Figure 26.

Identified potential transmission investments are subject to a bilateral study between the involved TSOs. In this type of study, preconditions can be adapted to more accurately reflect the regional power system, and relevant sensitivity analyses can be performed. A cost-benefit analysis similar to that used by ENTSO E will be performed. If the project is beneficial for the involved parties, the question of cost-sharing will have to be addressed before the project can be realised.

Regulation (EU) No 347/2013 introduced cross-border cost allocation (CBCA) as a regulatory tool to facilitate the implementation of projects of common interest (PCIs). CBCA claims can be submitted by project promoters and settled by regulatory authorities or ACER when a cost-benefit analysis (CBA) shows that a PCI generates a net negative impact for the host country while one or more third countries receive a net positive impact. The idea is that the cost shall be borne by the State(s) that benefit(s), regardless of its/their geographical proximity to or involvement in the project. The Nordic TSOs recognise the benefits of integrating the European energy markets and support the development of transmission capacity based on principles of welfare and voluntary agreements. However, CBCA is not an appropriate policy instrument and the project-by-project approach should be replaced with a more holistic view.

Encouraging states to work together to find mutually beneficial solutions, including cost-sharing, is a more efficient and appropriate strategy for further market integration. This approach has been proven to successfully facilitate market integration in and between the Nordic Region and Continental Europe. Replacing the CBCA with strong regional cooperation, where TSOs and authorities are involved with commitment and support, is therefore believed to be a more efficient way forward.

The Nordic TSOs agree that CBCA is increasing interconnector risk.

### 6.1.5 Efficient utilisation of transmission capacity

Securing adequate transmission capacity is not only a question of building overhead lines and cables, but also of utilising existing capacity efficiently. Allocation of transmission capacity within the day-ahead and intraday markets is regulated in the European Guideline on Capacity Allocation and Congestion Management (CACM). The guideline permits two approaches to calculating cross-zonal capacity for commercial power exchange: Flow-based or Coordinated Net Transfer Capacity. The preferred capacity

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# Transmission adequacy

**Drivers for grid development in the Baltic Sea region**

1. New interconnectors. Strengthen capacity from the Nordic countries to facilitate power export and to integrate different markets.

2. North South flows. Renewables in the northern areas and increased export capacity from the Nordic region increase incentives for internal north-south reinforcement.

3. Arctic consumptions. Establishment of new power intensive industries may create a need for reinforcements in northern areas.

4. Baltic integration. Market integration and energy security in the Baltic countries drive further interconnection to the Nordic and the European continental system.

5. Nuclear and other thermal decommissioning. The risk surrounding future system adequacy is increased.

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*Figure 26 Drivers for grid development in the Baltic Sea region (ENTSO-E 2015c)*

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# Transmission adequacy

calculation approach in CACM is flow-based since the physical properties of the transmission grid are better represented in the market algorithm under such an approach. Either option will involve a change to today's approach and result in more efficient utilisation of both production resources and transmission capacity. These options are currently being evaluated and a decision on which method that will be used in the Nordic day-ahead market is expected in the fourth quarter of 2016.

Besides the allocation of transmission capacity within individual markets, the issue of efficient allocation between markets needs to be considered. For example, the value of transmission capacity could sometimes be higher in the balancing market than in the day-ahead market. Methods for this type of evaluation are being developed by the TSOs, for instance in the "Hasle pilot", and these will help to secure more efficient transmission system.

## 6.2 Challenges in transmission system development

### 6.2.1 Challenge 1: Managing uncertainties in the development of the future power system

The greatest challenge regarding transmission system planning concerns the uncertainty of future developments. While the most important factors currently comprise the integration of wind power, changing economic conditions for thermal power production and consumption development, many further factors also come into play. Over the long term, technological developments on the demand side as well as in generation technologies and storage could significantly affect the power system.

It is necessary to consider several scenarios to capture some of the uncertainties. However, even a range of scenarios may not reflect all potential actual developments. For example, few analyses predicted the prevailing low electricity prices, and the pending large-scale decommissioning of thermal power plants. Furthermore, considering a large spread of scenarios may also not resolve the problem as these could be too improbable to provide meaningful support for any decision.

The challenges involved in making accurate predictions has increased in recent years. Falling electricity prices have pushed a large part of the thermal production to a tipping point in terms of continued operations. In the Nordic countries, as well as in the rest of Europe, the level of renewables in the power system is the subject of political debate, and discussions are underway on whether today's energy-only market is the best option for the future. The outcome of these issues will have a major impact on the need for transmission capacity, and it is likely that national political decisions and regulatory frameworks will play an important role in this context. The future of the $CO_2$ market and the development of European environmental targets will be of major importance for predicting the long-term power system.

The Nordic power system is impacted by neighbouring systems. In particular, German internal congestion has a significant effect on prices in southern Scandinavia during times of high production from renewable energy sources. Similarly, Finland and the Baltic countries are affected by trade with Russia, as illustrated, for example, by a number of sudden regulatory changes in the latter country in recent years. Any change in these issues will derive from political decisions outside of the Nordic countries, and will have a substantial impact on transmission capacity requirements. On a general level, predictions for the future power system will affect which transmission investments are made. Scenarios are used as a basis for analysis, where inaccurate predictions could result in socio-economic losses or inadequate security of supply. On the other hand, the fact that substantial potential gains can be made from many transmission investments means that postponing an investment decision can also result in a socio-economic loss.

A number of inherent factors are also increasing the complexity and sensitivity of scenario analyses. The Nordic region has an increasingly interconnected power system, which means that we are increasingly being affected by developments in neighbouring regions. This situation could also result in diminishing marginal gains. While the first interconnector between two areas may be an obvious investment, the benefit of a second or third interconnector is likely to be smaller and may require more detailed and robust analyses. The interdependencies between different transmission investments are affecting project evaluations, and the profitability of an interconnector may be greatly impacted by other projects.

#### 6.2.2 Challenge 2: Including additional power system values in transmission planning

The second challenge is to broaden our view of the application areas of transmission capacity for power system services, and to embrace those values in transmission planning. Historically, the focus of transmission planning has been on reducing congestions in the day-ahead market.

Transmission capacity plays an important role in ensuring security of supply. If local generation cannot meet demand, transmission capacity can be used for this purpose in the form of imports. Improved security of supply can be a main driver of a particular transmission investment, and this should be adequately reflected in the analysis and weighed against other costs and benefits. Transmission capacity could provide an alternative to local generation capacity with regard to improving security of supply.

To maintain stability in the power system, the generation and load in the system must be equal at all times. In the event of sudden failures or outages, reserve power must be generated and transferred to the places where it is needed. The transfer of reserve power is a system service whose value is not normally included in transmission planning. A recent pilot study concerning reservation of transmission capacity earmarked for frequency reserves was carried out for the connection between southern Norway and Sweden (Statnett 2015c). It showed that it was both possible and socio-economically viable to reserve capacity for frequency reserves during the tested weeks.

#### 6.2.3 Challenge 3: Balancing national, Nordic and European perspectives

Since the Nordic system is so strongly interlinked, it is important to adopt a Nordic perspective when planning for an efficient transmission system. The Nordic countries have a history of successful collaboration. Plans, data and ideas have been shared through numerous collaborations for the benefit of the Nordic TSOs. The Nordic perspective has also featured prominently in transmission planning: In the period 2002–2008, the Nordel cooperation published the Nordic Grid Master Plans, which were based on socio-economic benefits for the Nordic area (NordREG 2010).

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# Transmission adequacy

However, the Nordic perspective, and its relation to national and European values, is not clearly defined in any governing document. The Nordic energy regulators identified that the evaluation criteria for transmission investments were most often based on national socio-economic benefits, and that "a possible barrier related to the national evaluation criteria may arise if an investment is profitable for the Nordic region as a whole, but not for one particular country" (NordREG 2010). In practice it is not common for an investment project to be beneficial for the Nordic region but not for one of the involved countries; however, such a situation could occur and hence hinder adequate transmission system development.

### 6.2.4 Challenge 4: Maintaining operational security and an efficient market while reconstructing the grid

In addition to requiring new transmission capacity, the Nordic grid is old and in need of extensive reinvestment. Consequently, a very high volume of grid projects will be realised in the coming decade. One major challenge for the TSOs involves making the necessary investments in time to meet the future needs of the system while maintaining operational security and efficient markets during the construction phase. While development and increased application of live work will help meet this challenge, planned outages of grid components will nonetheless be very frequent in the coming decade, with resulting intermittently limited capacity. The investment portfolio shows that this is especially relevant for the next few years since investments for the TSOs peak in 2018, see Figure 4.

## 6.3 Possible solutions

The first set of proposed solutions focus on the TSOs' ability to remedy the issues of uncertainties:

- **Guide the power system when it is indecisive.** The TSOs have unique insight into the power system, and we should continuously communicate our knowledge. This would improve the conditions for regulators, policy makers and market actors to take informed decisions, and in turn reduce some of the uncertainties of the future power system.
- **Develop uncertainty analysis and results communication.** We use scenarios to illustrate the uncertainty space, but how should they be set up and evaluated? Should they "span a large space" of potential outcomes? These issues call for some caution in the interpretation of the results, and points to the importance of evaluating the analysis methods.
- **Develop modelling tools. There is room for improvement in our analysis models.** To correctly capture flexibility and to understand how capacity mechanisms influence the power system might be relevant areas of development.

The challenge to include additional values in transmission planning is TSO internal, and so is the proposed way forward.

- **Develop methods to include additional values in transmission planning.** The Hasle-pilot (Statnett 2015c) is an example of where a system service (reservation of capacity for balancing power) was valuated and weighed against the value of transmission capacity in the day-ahead market. Such development leads to a more efficient transmission system.

Ways to maintain and strengthen the Nordic perspective are suggested below.

- **Coordinate and align national grid development plans.** A first step could be to coordinate release dates. The plans could also include and elaborate on the general situation in, and the effects of investments on, the other Nordic countries.
- **Transparent objectives and analyses.** With transparent objectives and methods in transmission planning the Nordic perspective may become less elusive as a concept and communication become more straightforward.
- **Update overview of TSO mandates and directives.** The Nordic energy regulators identified different national legislation and TSO directives as a possible barrier to effective transmission investments in a Nordic perspective. The report was requested from the Electricity Market Group (EMG) under the Nordic Council of Ministers in 2008. Does the aim remain? In that case, an updated overview is probably warranted, not least with the increased influence of pan-European planning in mind.

# 7

# The way forward

The Nordic power system is changing, and not without consequences. This report concludes that these changes will result in the following challenges: An increased demand for flexibility, securing transmission and generating adequacy to guarantee security of supply, maintaining a good frequency quality and securing sufficent inertia in the system. These challenges were also identified in the Nordic strategy published by the four Nordic TSOs in 2015. The strategy summary showing a Nordic vision for 2025 is shown in Figure 28.

The identified challenges need to be addressed. If no measures are taken, there can be severe consequences. The need to address the various challenges is illustrated in the timeline in Figure 29, where the most important triggers (changes) that will exacerbate the challenges are also highlighted. The timeline illustrates the situation if no measures are taken. Action from the Nordic TSOs and other stakeholders in the Nordic power sector will reduce  the risk of the identified challenges.

There are, however, several solutions available, including market and technical measures. More extensive cooperation between the Nordic TSOs is a prerequisite for successful development and implementation of the available solutions; however, the Nordic TSOs cannot achieve everything on their own. Successfully developing the power system, will require extended cooperation across the power sector.

When it comes to ensuring enough system flexibility it is essential that the regulation of the market facilitate the most cost-efficient development and utilisation of available flexibility, which cannot be achieved by the TSOs alone. It is similarly necessary with broader collaboration to have the regulatory framework to adopt common definitions of generation adequacy that focuses on an socioeconomically efficient level of security of supply. A sufficient frequency quality can be obtained through a number of solutions that requires broader collaboration such as harmonizing of products and market solutions and an efficient allocation of transmission capacity to reserve markets. It is possible to avoid a too low level of inertia through technical adaption of existing power production units. There is also a need to clarify common goals for grid development in the Nordics which calls for an involvement of the regulators.

Some of the identified solutions are marked based where there need to be an agreement on which market model to develop and imple-

## Strategy summery

1. Ensuring a future robust Nordic power system
2. Maintaining current high level of security of supply
3. Better market support for adequacy
4. Empowering consumers
5. Strong Nordic voice in EU


*Figure 28 Strategy summary - A Nordic Vision for 2025*

ment. Other solutions are technical where cost and cost-sharing are the main issue. A third category of solutions is knowledge related - more insight is needed to evaluate the solutions. Many of the proposed solutions cannot be developed and implemented without extensive collaboration with the regulators and power industry. The power system is becoming more complex and more integrated. Cooperation both across contry borders and between different stakeholders is a prerequisite for success.

Research, development and demonstrations will also be required, especially where future solutions are unclear, and/or contain new technology or concepts. By further developing the R&D cooperation between the Nordic TSOs, an increased commitment and more efficient information sharing is achieved.

The challenges addressed in this report present very welcome input for the Nordic R&D roadmap which is due to be published in 2017. The roadmap gathers the various elements of the Nordic Flagship R&D project and schedules these into achievable milestones in the coming years.

In addition to engaging with the broader Nordic power sector, the TSOs will also intensify their own collaboration. The TSOs will follow up this report with a second phase. As presented in this report the challenges are on different maturity level and some challenges needs to be further analysed while for others we can agree on solutions. The TSOs hence aim in the next phase to 1) Quantify challenges where needed, 2) Assess the value of the solutions, 3) Compare solutions, and 4) Agree on the right solutions. The aim of this phase is thus to take the cooperation a step further and agree on measures.

## Timeline of the identified challenges

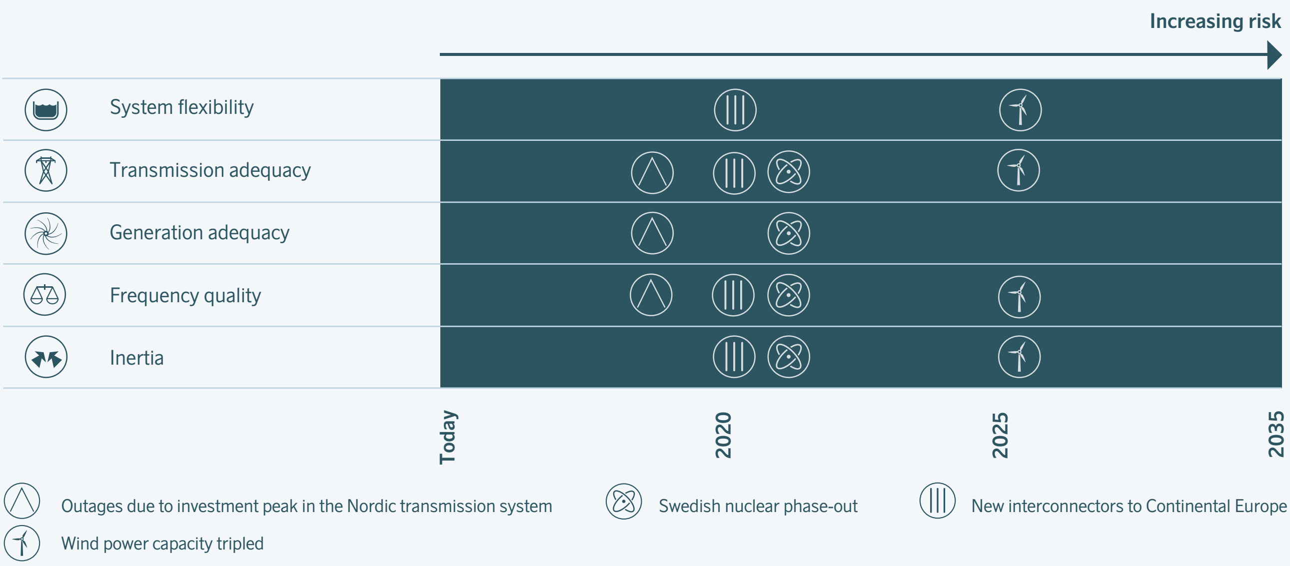


*Figure 29 Timeline fo the identified challenges. The figure include four triggers (changes) that will exacerbate the challenges. Leading up to 2025 and beyond, the risk of the identified challenges will increase if no measures are taken.*

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# Appendix 1

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## Definitions

**Definitions of key concepts:**

**Adequacy** is the ability of an electric power system to supply the aggregate electric power and energy required by the customers, under steady-state conditions

**a) Generation adequacy:** An assessment of the ability of the generation capacity of the power system to match the Load in the power system.

**b) Transmission adequacy:** An assessment of the ability of a power system to manage the flows in the grid resulting from the location of Load and generation.

**c) System adequacy** of a power system is a measure of the ability of a power system to supply the load in all the steady states in which the power system may exist considering standards conditions. System adequacy is analysed through Generation Adequacy and Transmission Adequacy (main focus on generation capacity and load and on simultaneous interconnection transmission capacity).[10]

**Balancing:** All actions and processes, on all timelines, through which TSOs ensure, in a continuous way, to maintain the system frequency within a predefined stability range, and to comply with the amount of reserves needed per Frequency Containment Process, Frequency Restoration Process and Reserve Replacement Process with respect to the required quality.[10]

**Flexibility** is the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand Power system flexibility represents the extent to which a power system can adapt power generation and consumption as needed to maintain system stability in a cost-effective manner. Flexibility services include "up-regulating and down-regulating" that provides additional power as needed to maintain system balance, and "down-regulation" that reduces the power generation in the system. Contingency (short-term) reserves are required for ensuring power system stability in the event of large power system component outages. Ramping capability is an expression of how fast flexible resources can change demand or supply of power. [11]

**Frequency stability:** The ability of the Transmission System to maintain stable frequency in N-Situation (where no element of the Transmission System is unavailable due to a Fault) and after being subjected to a disturbance.[10]

**Inertia:** 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.[10]

**Synthetic inertia:** 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.[10]

*[10]ENTSO-E 2016. Definitions and Acronyms. Retrieved March 12, 2016, from Glossary: https://emr.entsoe.eu/glossary/bin/view/GlossaryCode/GlossaryIndex*
*[11]ECOFYS 2014. Flexibility options in electricity systems. Berlin: ECOFYS Germany GmbH.*

# Appendix 2

## Inertia

### Methodology

**Hourly kinetic energy estimation**

Hourly power productions of the different production types in the different bidding zones are used in order to estimate available kinetic energy during each hour of the target year (2025) for each production type and bidding zone. The following equation is used in the estimation:

$$W_{\text{kin}} = \frac{P \cdot H}{p \cdot \cos\phi}$$

where $W_{kin}$ is kinetic energy in gigawattseconds, $P$ is aggregate active power production of the production type in the specific bidding zone, $H$ is average inertia constant of the production type in seconds, $p$ is the average ratio of actual power production divided by the sum of rated power values ($P/\sum P_{Ri}$) of the production type in the specific bidding zone, and cos $\phi$ is the average power factor ($P_R/S_R$). The power productions are variables and based on the hourly market simulation scenario used throughout the report. The other parameters are assumed constant.

The following categorisation of the power production types and the average inertia constants (in parenthesis) are in most cases used for each production type[12]:

- nuclear ($H$ = 6.3 s)
- other thermal ($H$ = 4 s)
- hydro conventional ($H$ = 3 s)
- hydro small-scale ($H$ = 1 s)
- wind and solar ($H$ = 0) => no kinetic energy

For $p$, the value of 1 is used for other production categories except for hydro a value of 0.8 is used. This means that rated power production of each unit for other production types is assumed ($p$ = 1, a conservative estimate). For hydro, 80 % production of their rated capacity is assumed on average. The 80 % assumption for hydro is because the efficiency of a hydro generator is usually at maximum around 80 % production[13].

For the power factor, cos $\phi$ an average value of 0.9 is assumed for each production type.

### Hourly total inertia for all climate years

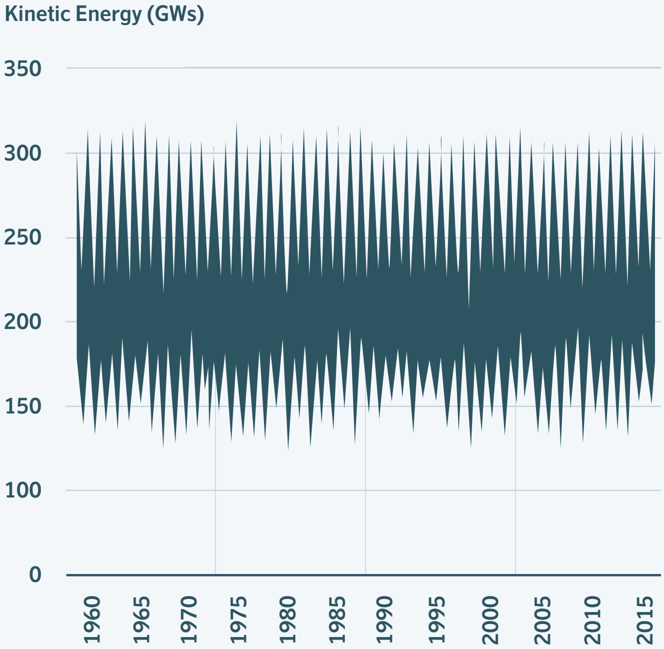


*Figure 30 Hourly total inertia for all climate years.*

Exceptions of the above values are such that for Eastern part of Denmark (DK2), other thermal production the values of $H$ and $p$ are 3 and 0.5, respectively.

**Simulation of disturbances**

In order to estimate the required amount of kinetic energy in different situations, the E-Bridge RAR (Requirements for Automatic Reserves) Simulink model[14] is used to find out minimum kinetic energy that is needed to withstand the tripping of the largest unit. It is assumed that the step size will be –1450 MW (equivalent to the tripping of Oskarshamn 3). Olkiluoto 3 will be 1600 MW but it has a system protection scheme (SPS) of 300 MW reducing its tripped power to 1300 MW. If the loads of the SPS are not connected, the plant runs at 1300 MW. In a normal case, the load self-regulation (frequency dependence) is assumed to be 0.75 %/Hz and the reserves are the same as typical reserves in 2016. This is because the amount and behaviour of the

*[12]ENTSO-E 2015. Nordic Report Future System Inertia. Brussels: ENTSO-E. [13]Björnstedt, J. 2012. Integration of Non-synchronous Generation, Frequency Dynamics. Lund University: Department of Measurement Technology and Industrial Electrical Engineering. [14]E-Bridge Consulting GMBH 2011. Analysis & Review of Requirements for Automatic Reserves in the Nordic Synchronous System - Simulink Model description . Bonn: E-Bridge Consulting GMBH.*

# Inertia

future reserves is not yet known. In this normal case, it is conservatively assumed that the initial frequency is 49.9 Hz and all the normal reserves (FCR-N) have already been activated before the trip. In the simulations, the acceptable minimum frequency after the trip is 49 Hz as has been assumed in the Nordic analyses earlier.

### Hourly amount of kinetic energy

Hourly estimated amount of kinetic energy during 2025 for each climate year is presented in Figure 30, and durations of kinetic energies per bidding zone for all climate years are presented in Figure 31.

### Sensitivity analyses

### Uncertainty in the amount of kinetic energy

Table 4 and Table 5 present a comparison between the original market simulation scenario for 2025 and a scenario with the half of nuclear production. In the scenario with the half of nuclear power, it is assumed that only half of the nuclear production of the original scenario is available. The assumption is that the nuclear production is replaced with higher import and wind and solar production.

In the scenario with the half of nuclear power, the percentage of time when the kinetic energy is below the required amount is 22 % (1901 hours per year) when all climate years are taken into account. For dry year conditions (1969), the duration is 39 % (3355 hours per year), and for wet year conditions (2000) the duration is 4.2 % (369 hours per year). In the full nuclear scenario, the respective durations are 7.7 %, 18 %, and 0.7 % (meaning 673, 1616, and 63 hours per year).

| All climate years | Full nuclear | Half nuclear |
|---|---|---|
| Kinetic energy (GWs) min. | 83 | 63 |
| Kinetic energy (GWs) max. | 315 | 277 |
| Kinetic energy (GWs) mean | 194 | 161 |
| Kinetic energy (GWs) median | 191 | 159 |

*Table 4. Statistical information of the estimated amount of kinetic energy with full nuclear scenario (the original market simulation scenario for 2025) and a scenario with half of nuclear production.*

## Duration of total Kinetic Energy

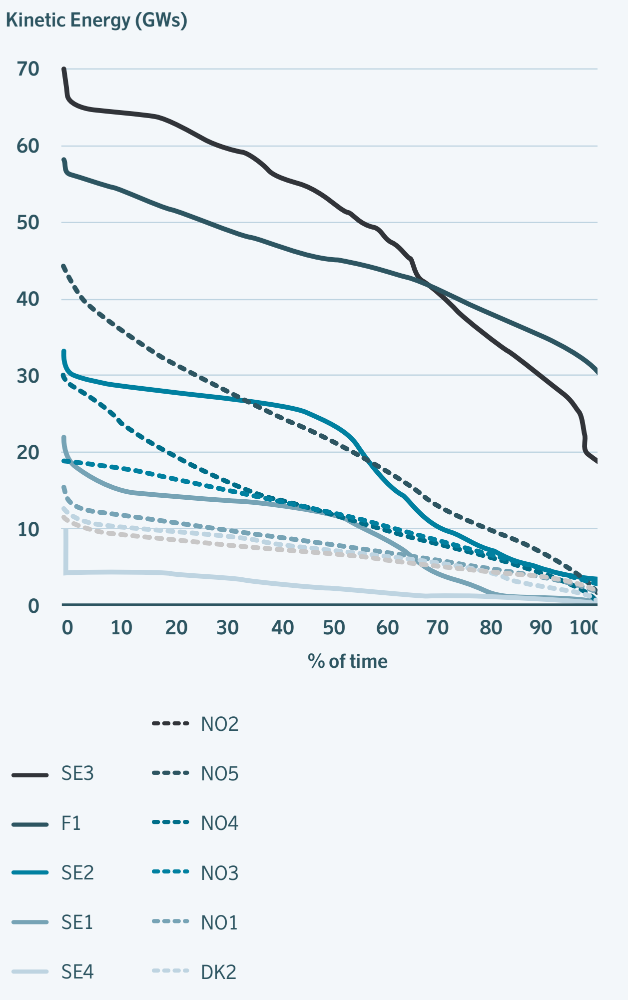


*Figure 31 Durations of kinetic energies per bidding zone for all the climate years.*

# Appendix 2

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## Inertia

| All climate years | Number of hours per year | | % of time | |
|---|---|---|---|---|
| Kinetic energy (GWs) below | Full nuclear | Half nuclear | Full nuclear | Half nuclear |
| 85 | 0.078 | 110 | 0.00089 | 1.3 |
| 90 | 1.1 | 222 | 0.013 | 2.5 |
| 95 | 3.9 | 367 | 0.045 | 4.2 |
| 100 | 15 | 534 | 0.17 | 6.1 |
| 110 | 99 | 985 | 1.1 | 11 |
| 120 | 325 | 1585 | 3.7 | 18 |
| 130 | 613 | 2274 | 7.0 | 26 |
| 140 | 973 | 2978 | 11 | 34 |
| 150 | 1487 | 3681 | 17 | 42 |

*Table 5. Number of hours per year and the share of time when the estimated inertia is below the indicated values for the full nuclear (the original scenario) and for a scenario wi]half of nuclear production.*

| Duration of time in percentage (hours per year) when the kinetic energy is below the requirement | Average power of the units, p (pu) | | | | |
|---|---|---|---|---|---|
| H (percentage of the values of the original values scenario) | Conventional hydro: 0.6, others: 0.8 | Conventional hydro: 0.7, others: 0.9 | Conventional hydro: 0.8, others: 1 | Conventional hydro: 0.9, others: 1 | All: 1 |
| 80 | 7.1 % (618) | 14 % (1191) | 23 % (1994) | 28 % (2432) | 33 % (2894) |
| 90 | 3.3 % (274) | 7.7 (672) | 14 % (1191) | 17 % (1507) | 21 % (1815) |
| 100 | 0.84 % (74) | 3.9 % (345) | 9.7 % (849) | 10 % (915) | 13 % (1126) |
| 110 | 0.15 (13) | 1.5 % (130) | 4.7 % (409) | 6.4 % (559) | 8.1 % (709) |
| 120 | 0.02 (1.6) | 0.35 % (31) | 2.1 % (187) | 3.4 % (294) | 4.6 % (407) |

*Table 6. Sensitivity of the duration of time when the inertia (measured by kinetic energy) is below the requirement as a function of average generated power of the units (p) and average inertia constants (H) for all bidding zones ( including DK2).*

### Maximum Disconnected Power

Sensitivity of the required amount of inertia with respect to the disconnected power is presented in Table 7.

| Disconnected power (MW) | 1000 | 1100 | 1200 | 1300 | 1400 | 1500 | 1600 |
|---|---|---|---|---|---|---|---|
| Required amount of kinetic energy (GWs) | 48 | 62 | 79 | 101 | 128 | 166 | 217 |

*Table 7. Sensitivity of the required amount of inertia as a function of the disconnected power.*

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## Inertia

**Initial frequency and minimum frequency after the trip**
Sensitivity of the required amount of inertia depending on the range of frequencies is presented in Table 8. For the assessment of the probability of the different initial frequency values, historical data on the frequency behaviour is presented in Table 12.

| Required amount of kinetic energy (GWs) | Minimum frequency (Hz) after the trip | | | |
|---|---|---|---|---|
| Initial frequency (Hz) | 48.8 | 49 | 49.2 | 49.5 |
| 50 | 58 | 96 | 191 | 833 |
| 49.95 | 65 | 114 | 239 | 1130 |
| 49.9 | 78 | 145 | 329 | 1927 |

*Table 8. Sensitivity of the required amount of kinetic energy as a function of the initial frequency and minimum frequency after the trip.*

**Amount of Reserves**
Sensitivity of the required amount of kinetic energy on the amount of reserves is presented in Table 9. The amount and behaviour of reserves in 2025 is not yet known, therefore the usual reserves in 2016 are used as a reference. The simulations are carried out in such a way that the output of the reserves is multiplied with the ratios indicated in the table. The response of the reserves is otherwise kept the same.

| Amount of reserves (percentage of the reference reserves: usual reserves in 2016) | 80 | 90 | 100 | 110 | 120 | 130 | 140 |
|---|---|---|---|---|---|---|---|
| Required amount of kinetic energy (GWs) | 269 | 192 | 145 | 119 | 102 | 89 | 79 |

*Table 9. Sensitivity of the required amount of kinetic energy as a function of the amount of reserves.*

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# Inertia

### Load self-regulation and amount of Load

Sensitivity of the required amount of kinetic energy as a function of the load self-regulation (frequency dependence) and amount of load is presented in Table 10. Historical data on the minimum load can be found in Table 11 for the assessment of probable minimum load.

| Required amount of kinetic energy (GWs) | Load self-regulation (% / Hz) | | | | | | |
|---|---|---|---|---|---|---|---|
| Amount of load (GW) | 0 | 0.25 | 0.5 | 0.75 | 1 | 1.5 | 2 |
| 20 | 234 | 211 | 189 | 170 | 153 | 125 | 104 |
| 25 | 234 | 205 | 179 | 157 | 138 | 109 | 86 |
| 30 | 234 | 200 | 170 | 145 | 125 | 95 | 71 |
| 35 | 234 | 194 | 161 | 134 | 114 | 82 | 58 |
| 40 | 234 | 189 | 153 | 125 | 104 | 71 | 47 |
| 45 | 234 | 184 | 145 | 117 | 95 | 61 | 39 |
| 50 | 234 | 179 | 138 | 109 | 86 | 52 | 31 |
| 55 | 234 | 175 | 131 | 102 | 78 | 45 | 25 |
| 60 | 234 | 170 | 125 | 95 | 71 | 39 | 21 |

*Table 10. Sensitivity of the required amount of kinetic energy as a function of load self-regulation and amount of load.*

### Historical data analyses

| All climate years | Min. consumption in the sync. area (GW) | Consumption over 30 GW in the sync. area ](% of time) |
|---|---|---|
| 2013 | 24.1 | 90.5 |
| 2014 | 24.9 | 91.2 |
| 2015 | 26.5 | 94.4 |

*Table 11. Minimum load in the synchronous area and the share of time when the consumption is over 30 GW.*

| Frequency below | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|---|
| 49.90 | 0.624 | 0.764 | 0.947 | 1.04 | 0.933 | 0.967 | 0.932 | 0.961 |
| 49.92 | 2.19 | 2.47 | 2.93 | 3.09 | 2.93 | 2.85 | 3.02 | 3.11 |
| 49.94 | 6.83 | 7.07 | 8.04 | 8.18 | 8.00 | 7.58 | 8.12 | 8.33 |
| 49.96 | 16.3 | 16.5 | 18.0 | 18.1 | 17.9 | 17.1 | 18.0 | 18.3 |
| 49.98 | 31.3 | 31.3 | 32.7 | 32.6 | 32.5 | 31.8 | 32.8 | 33.0 |

*Table 12. The share of time (%) when frequency is below the indicated frequency.*

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## Status of investment in the Nordic power system

Based on a request from the Electricity Market group under the Nordic Council of Ministers, in the years of no publication of Nordic Grid Development Plan, the Nordic TSOs will publish a status update of the Nordic grid investments.

### Nordic grid planning

In 2014 Nordic TSOs re-established a Nordic planning group in order to ensure continuous Nordic focus in regional transmission planning.

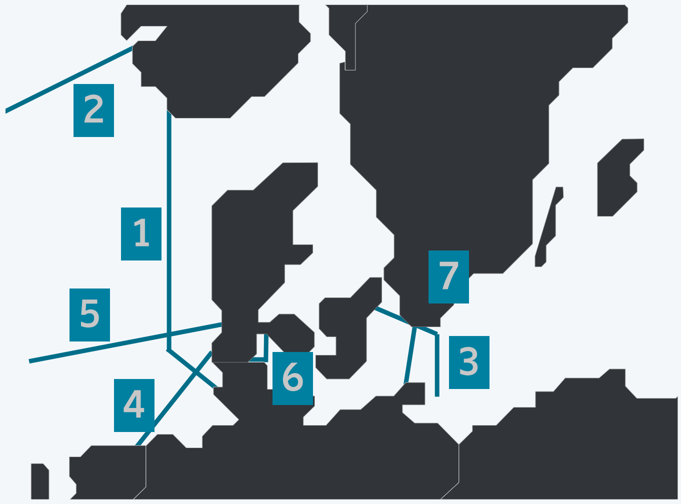
Nordic TSOs take part both in common Regional planning in ENTSO-E (in Regional groups Baltic Sea and North Sea) and cooperate in grid planning issues on Nordic level (Nordic Planning Group).

All the Nordic TSOs are currently in a middle of high investment activities both due to expected power system changes caused by the increased installation of renewable generation and due to re-investments caused by aging of power system components.

### Status of selected Nordic projects

Increased capacity, Nordics to Continent (incl. Great Britain)

**Increased capacity, Nordics to Continent (incl. Great Britain)**




**Planned projects**

| | | |
|---|---|---|
| Norway–DE | 1400 MW | 2020 |
| Norway–GB | 1400 MW | 2021 |
| Sweden–DE | 700 MW | 2025 |
| DKwest–NL | 700 MW | 2019 |
| DKeast–DE | 400 MW | 2018 |
| DKwest–GB | 1400 MW | 2022 |
| DKwest–DE (two projects) | <=2000MW | <=2022 |

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## Status of investment in the Nordic power system

| Increased capacity, Nordics to Continent (incl. Great Britain) | Planned projects |
|---|---|
| **(1)** Norway–Germany (Nord Link) 1400 MW.<br>Licenses permitted, investment decided, construction started. | 2020 |
| **(2)** Norway–England (North Sea Link) 1400 MW.<br>Licenses permitted, investment decided, construction started. | 2021 |
| **(3)** Eastern Denmark–Germany 400 MW (Kriegers Flak): Together with German TSO 50Hertz Transmission GmbH offshore interconnector for the Kriegers Flak offshore wind farm is being developed. The new interconnector will take advantage of the proximity of Danish and German wind farms by adding short cables and thus connecting the wind farms to both Germany and Denmark. The European Commission is supporting the interconnection with up to 150 m€. The tendering for the project is in progress and the first main equipment is ordered. All contracts are expected to be signed by the end of 2016. | 2019 |
| **(4)** Western Denmark–Netherlands 700 MW (Cobra): The project obtained in the summer 2014 a conditional investment approval by the Danish and Dutch Ministries. Contracts have been awarded to Prysmian for the cables and to Siemens for the converter stations in January 2016. With the contract award the project enters the Construction phase, with planned installation works in 2017-18 followed up by commissioning and operation in Q1 2019. | 2019 |
| **(5)** Western Denmark–Great Britain 1400 MW (Viking Link):<br>The project is making good progress and is following the project plan. The project is in the feasibility and planning phase. Expected commissioning is in late 2022. Request for §4 approval has been submitted to the Danish Energy Agency during winter 2016. The sea bed survey is in progress and will be finished during autumn 2016. | 2022 |

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## Status of investment in the Nordic power system

| Increased capacity, Nordics to Continent (incl. Great Britain) | Planned projects |
|---|---|
| **(6)** Western Denmark–Germany: The project is in two parts, East Coast and West Coast. The East Coast project is an upgrade of the existing 220 kV line over the border to 400 kV which will increase the trading capacity from 1500/1780 MW to 2500/2500 MW. This will in Kassø connect to the 400 kV backbone from Kassø to Tjele which was upgraded in 2014. Energinet.dk is still awaiting §4 approval of request submitted to the Danish Energy Agency.<br><br>The West Coast project being studied is a connection from Endrup (DK) to Niebüll (DE) as a 400 kV double circuit. This will increase capacity on the border from 2500 MW to 3500 MW. Request for §4 approval has been submitted to the Danish Energy Agency during winter 2016. | 2022 |
| **(7)** Sweden–Germany 700 MW (Hansa PowerBridge)<br>Svenska kraftnät and the German TSO 50 Hz are planning a new interconnector. A joint pre-feasibility study was done in 2014 and was followed by internal studies. A cooperation agreement to continue with more detailed preparatory work was signed in late 2015 and the first investment decisions are planned for the first part of 2017. A second interconnector (Hansa PowerBridge 2) will later also be considered. | 2025 |

**Increased capacity between the Nordic and Baltic systems**

Today the Baltic power system is synchronised with the Russian system. Based on security of supply and based on geopolitical risks, the European Commission aims for a Baltic system stronger connected to the Continental and the Nordic system. This is also the main driver for the increased capacity between the Baltic and the Nordic systems. Two interconnectors were lately commissioned. Additional DG Eenergy evaluates a desynchronisation of the Baltics from the Russian system. One of the evaluated alternatives is synchronisation the Nordic system with the Baltic system.

| Project | Commissioned |
|---|---|
| Estlink 2 (Finland–Estonia, 650 MW) | 2014 |
| NordBalt (Sweden–Lithuania, 700 MW) | 2016 |

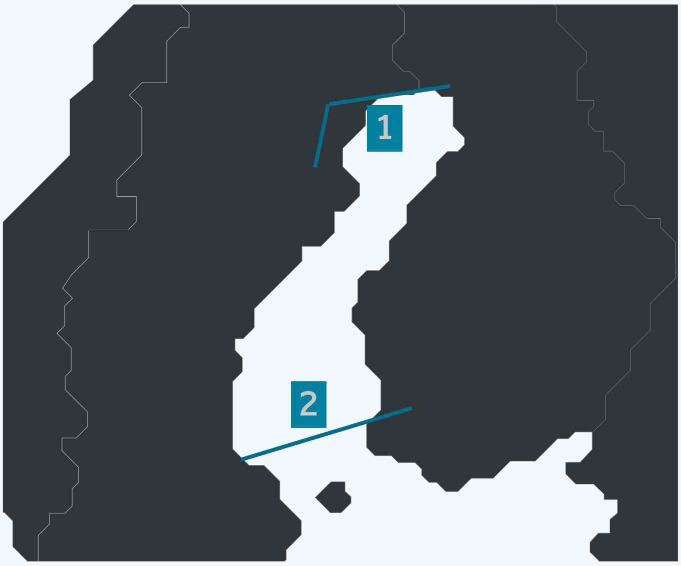
# Appendix 3

# Status of investment in the Nordic power system

| Increased capacity, North–South in the Nordics | Planned projects |
|---|---|
|  | Finland 2015–2024<br>Sweden 2017–2025<br>Norway 2016–2022 |
| **Finland** Three 400 kV AC lines still to be commissioned<br>• **(1)** Hirvisuo–Pyhänselkä 400 kV AC line in construction, planned commissioning 2016<br>• **(2)** Petäjävesi–Pyhänselkä 400 kV AC line, EIA done 2012, route selected 2013, expected into operation by 2023<br>• **(3)** Keminmaa–Pyhänselkä 400 kV AC line expected 2024 | |
| **Sweden (from North to South)**<br>• Series compensation between bidding zones SE1 and SE2 is still considered in combination with other reactive compensation alternatives between SE2 and SE3. There is today no expected commissioning date for these investments.<br>• New shunt compensation and upgrades of existing series compensation between bidding zones SE2 and SE3 are planned for installation between 2017 and 2025. This will increase the north–south capacity.<br>• **(4)** Studies have started on how to replace the oldest 400 kV lines with new and stronger lines. This will also lead to an increased capacity for power flows between SE2 and SE3. | |
| **In Norway** many projects **(5)** are planned in order to increase the North-South capacity. Among the most important projects are:<br>• Ofoten–Balsfjord–Skaidi; to be commissioned 2016–2020<br>• Voltage upgrades through north and mid of Norway<br>• New lines in Mid-Norway (Fosen)<br>• Ørskog–Sogndal; to be commissioned 2016/2017<br>• Vestre Korridor; to be commissioned 2017–2022 | |

# Appendix 3

## Status of investment in the Nordic power system

<table>
<tr><th>Increased capacity, Finland–Sweden</th><th>Planned projects</th></tr>
<tr><td>

Svenska kraftnät and Fingrid have started a joint study in 2015 to analyze transmission needs between Sweden and Finland. The study will include the third AC-line in the North and replacement of Fenno-Skan 1 at the current location or between areas SE2–FI. Renewal of Fenno-Skan 1 is studied with existing or increased capacity. Capacity study is expected to be completed in autumn 2016.</td><td>400 kV AC line 2025<br>Renewal of Fenno-Skan 1 ~2030</td></tr>
<tr><td>(1) Finland–Sweden 400 kV AC line</td><td>2025</td></tr>
<tr><td>(2) Renewal of Fenno-Skan 1 link. The link is currently operated with a reduced capacity due to cable conditions.</td><td>2030</td></tr>
</table>

# Appendix 3

## Status of investment in the Nordic power system

| Securing the Arctic region | Planned projects |
|---|---|
|  | 400 kV line Norway 2016/2021<br>Reinforcing 220kV Finland–Norway |
| **Norway**<br>Statnett is building the new line **(1, 2)** Ofoten–Balsfjord–Skaidi in order to obtain an adequate SoS for the region. The first part of the line (Ofoten–Balsfjord) will be commissioned in 2016/17 while the second part (Balsfjord–Skaidi) is planned to be commissioned in 2021. A line further east (Skaidi–Varangerbotn) is planned, however no decisions taken. | |
| **Finland–Norway.** Statnett has completed a Concept Selection Study for the North of Norway. Based on the study Statnett has concluded that, assumed increased petroleum activity, a new line from Finland to the north of Norway might be beneficial. Capacity increase of the existing 220 kV connection Norway–Finland is also studied. **(3)**. | |

**Nordic Prioritised Cross-Sections, 2004**

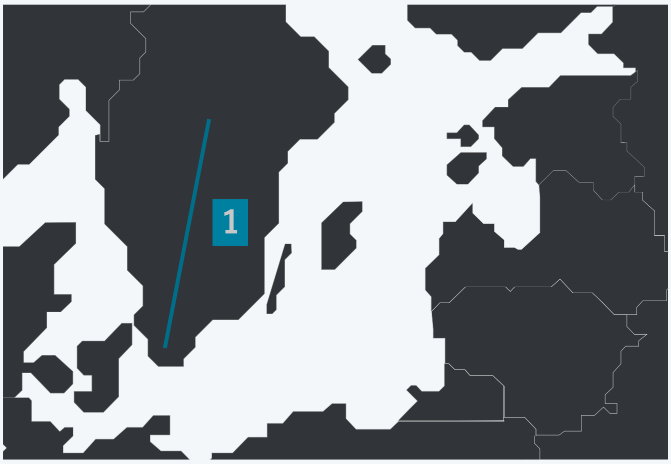
In 2004 Nordic TSOs agreed on reinforcing five prioritised cross-sections.

Out of the suggested five projects, four have been commissioned while for the last one (SouthWest Link), the western part was cancelled due to changed circumstances and needs. The original Swedish part of the project are about to be fully commissioned (details below).

| Project | Commissioned |
|---|---|
| Fenno–Skan 2 | 2011 |
| Nea–Järpströmmen | 2009 |
| Great Belt | 2010 |
| Skagerrak 4 | 2014 |
| SouthWest Link Sweden | More details below |

# Appendix 3

## Status of investment in the Nordic power system

| SouthWest Link | Planned projects |
|---|---|
|  | **(1)** The SouthWest Link is in its final phase of completion. The northern part is realised as a 400 kV AC overhead line and was taken into operation in April 2015. The first of the two HVDC-links in the southern part is scheduled to be taken into operation in the autumn of 2016 and the second in the middle of 2017. |

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