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Summary and Conclusions

The electricity system in Europe is going through a profound transition both in terms of the composition of the generation capacity and in terms of increased integration. The transition is both technical and economical, as conventional thermal capacity is replaced by subsidized renewable generation, and as cross-border trade increases due to increased capacity and increased market and regulatory efficiency.

The increase in the share of intermittent renewable generation and reduced profitability of conventional power generation has however led to a growing concern for capacity adequacy in the market. The Nordic and Baltic market (Nord Pool market area) is faced with similar challenges. Generally, it does not make sense to assess capacity adequacy for each country separately. This is especially the case for the Nord Pool market area, as it is highly integrated in terms of both interconnector capacity and market integration. Capacity challenges are rarely isolated to one country or bidding zone.

This report analyse the following issue

What market solutions may be used to manage capacity adequacy in the Nord Pool market area, and how could an efficient transition to adequate market solutions be achieved?

Several countries in Europe have implemented, or consider implementing, so-called capacity mechanisms. Such mechanisms may adversely affect market efficiency. Therefore, the EU Commission has issued guidance on public intervention, including measures that should be considered before capacity mechanisms are implemented (EC checklist). In line with the EC checklist, we focus on measures to improve the functioning of the energy-only market design in the Nord Pool market area, i.e. on measures to strengthen capacity adequacy apart from implementing separate capacity mechanisms.

As a basis for the analysis, we assess the current and future capacity situation in the market, including the market design and the regulatory framework. The report takes an outlook to 2030.

We define capacity adequacy as *the system's ability to establish market equilibrium in the day-ahead market, and at the same time provide adequate balancing resources for real-time operation, even in extreme situations.*

We note that capacity adequacy is linked both to price formation in the day-ahead market, and the physical balancing of the system in real-time.

Moreover, there are three main aspects of capacity adequacy:

- Peak load: Do we have sufficient capacity (including demand response) to handle peak load situations?
- Flexibility: Is the capacity (including demand) sufficiently flexible to handle variations in load and balance the system in real-time?
- Energy back-up: Do we have sufficient energy back-up capacity to serve demand during prolonged periods of low wind and solar generation?

Three-step capacity adequacy assessment

A comprehensive capacity adequacy assessment should consist of the following three steps:

1. Model based scenario assessment; in order to identify possible capacity adequacy challenges.
2. Assessment of the potential for market-based contributions from trade, supply, and demand; the profitability and potential for increased supply, demand response, and exchange with other markets.
3. Assessment of regulatory and market barriers to capacity adequacy.

We would like to emphasize that a model based scenario analysis, however sophisticated, cannot be regarded as a complete assessment of future capacity adequacy in a market. Inclusion of step 2 and 3 is essential, and in compliance with the EC checklist for market intervention.

Neither a common Nordic nor country individual reliability standards are defined for the Nordic market area. If reliability standards are to be defined, the approach should be coordinated between the Nordic TSOs, and the reliability standard should be expressed in terms of Loss Of Load Expectation (LOLE) or Expected Energy Unserved (EEU), and not in terms of a de-rated capacity margin. This is because the de-rated capacity margin approach is static and does not take into account the correlation of different risk factors.

Lack of experience data when it comes to both demand side contributions and the impact of changes in the market and regulatory framework on investment decisions, imply, however, that LOLE and EEU estimates will be very inaccurate. LOLE and EEU estimates are inherently linked to the *modelling* of capacity adequacy, and not to actual market outcomes.

Step 1: Model based scenario analysis

In this report, we present existing market scenarios and adequacy assessments. These shed light on the future capacity situation in different parts of the market. We supplement these assessments by conducting a simplified model analysis using the The-MA power market model. The model simulations are based on a reference scenario and the definition of six stress cases for the market. The probability of the different situations are not assessed. We would like to emphasize that the model exercise is simplified and should be regarded as an illustration. It is however, a useful starting point for the subsequent analysis.

The main conclusion is that there is little evidence of severe capacity adequacy challenges in the Nord Pool market area to 2030. We do however identify the availability of nuclear generation and interconnector outages as potential sources for capacity shortages. In particular, the combination of substantially reduced nuclear availability and multiple interconnector outages in a cold and dry winter will be challenging. The probability of this case is very low, however.

The Nordic market as a whole is likely to rely on imports during maximum peak hours, but this is not likely to pose a problem, as the Nord Pool market area has ample exchange capacity with several other markets. The Baltic area generally has a surplus during peak load, however.

The model simulations indicate that neither energy back-up nor flexibility is likely to be significant challenge in the Nord Pool market area. The main reason for this is the large share of flexible hydropower generation, and the ample interconnector capacity within the Nord Pool market area, and between the Nord Pool market area and other markets. Hence, we mainly focus on the adequacy of peak capacity in the next steps of the analysis.

Step 2: Potential for market-based contributions from trade, supply, and demand

Can we rely on imports form other markets in maximum peak hours in the future? Adjacent markets are likely to become increasingly integrated and efficient with the implementation of the European target model and flow-based market coupling. Implementation of (individual) capacity mechanisms in other markets may be beneficial, but may also have adverse effects on Nordic capacity adequacy if provisions for cross-border participation are not made. In order to mitigate such adverse effects, the Nordic countries should support requirements for facilitation of cross-border participation in capacity mechanisms in adjacent markets.

Although investments in new gas power generation (peak and CCGT) do not appear to be profitable in the 2030 timeframe, additional investments in hydropower capacity may be profitable if price levels and price variations increase. There is a substantial potential for increased peak and flexible generation in Norwegian hydropower and probably some potential in Finnish and Swedish hydropower as well.

Studies identify substantial potentials for demand response in the Nordic market. Both the potential and the price levels at which the potential can be activated, are uncertain. The uncertainty is due to historically relatively low electricity prices and small price variations, in combination with market and regulatory barriers for demand response participation. Hence, historical data provide poor indications of future demand response potentials.

Step 3: Regulatory and market barriers to capacity adequacy

Generally, the Nordic electricity market is well-functioning and highly liquid. However, in view of possible future capacity challenges, we have identified some relevant barriers which may adversely affect future capacity adequacy. Efficient short-term operation of the system and efficient long-term investments rely on efficient price formation, adequate cost recovery and making sure that price signals reach suppliers and consumers.

Although the probability of capacity shortages is low, some changes in the market design are merited.

1. Efficiency of wholesale price formation.

The wholesale prices formed in the day-ahead market (Elspot) should yield firm and efficient market signals. The price cap in the Elspot market does not seem to constitute a capacity adequacy concern, as the maximum price is rarely achieved. However, soft price caps may exist, as measures taken by the TSOs before Elspot gate closure may reduce scarcity pricing, and due to the pricing rule for the peak capacity reserves in Finland and Sweden. The pricing rule for the PLR should be reassessed, and the TSOs should implement clear and transparent rules for determination of ATC values. Grid measures may be efficiently used to handle possible shortage situations, but should not be implemented prior to gate closure in Elspot.

Similarly, bidding zone delimitation should be based on structural bottlenecks, rather than be fixed. The efficiency gains from flow-based market coupling are also likely to depend on the efficiency of the bidding zone delimitation.

2. Liquidity in the intraday market and the cost of imbalances.

The cost of imbalances and the efficiency of balancing is likely to be improved if imbalances can be managed as early as possible and in the spot markets. Implementation of 15-minute time resolution allocates a larger share of imbalances to the balance-responsible parties, and should increase the activity in the intraday market (Elbas).

Today, generators have a stronger incentive to be in balance than consumers do, due to the two-price system for imbalance settlement. We observe that the weaker incentives for consumers may contribute to shortage situations in the Elspot market, and reduce their incentives to use the intraday market for balancing. This system should be reviewed.

Moreover, all market agents, including aggregators, should be balance responsible. Some have suggested that aggregators should be exempt from the balance responsibility, in order to stimulate increased supply of demand response in the market, but such an exemption is likely to increase the overall balancing costs in the system.

Reserve markets may be improved by harmonizing product definitions and integrating markets. The possibility of reserving interconnector capacity for exchange of reserves should be pursued within current European regulation.

Product definitions in the reserve markets should be further developed in order to facilitate demand-side participation, provided of course that the products also provide the necessary resources for real-time operation of the system.

3. Efficiency in provision of ancillary services.
Provision of ancillary services should be properly remunerated or acquired on market based terms, instead of being set as requirements for certain generators. We have not analysed the current framework for ancillary services provision in the Nord Pool market area. A study of Germany does however, point to the ancillary services provision as a possible cost driver for conventional generation capacity, and as such a barrier to investments. To the extent allowed by the connection requirements in the new Network codes, the Nordic TSOs should review the scope and appropriateness of the current provisions.

4. General regulatory design.
The design of renewable support mechanisms should be revised. The Elcertificate market and the feed-in tariffs used in the Nordic area (with the exception of the feed-in tariffs for new offshore wind in Denmark and feed-in tariffs in Finland) may increasingly undermine the profitability of conventional power generation and exacerbate capacity adequacy challenges. In general, even renewable generation should be exposed to market prices, i.e. its varying market value. Subsidies that are provided even in hours when prices are below zero is problem in particular as it increases the loss incurred to avoid start-up costs in conventional capacity. Although negative prices are rarely seen in Norway, Sweden, and Finland, they may become more frequent in the future.

A number of regulations and policy measures affect capacity adequacy in the market. Energy efficiency measures, taxes and levies on energy consumption and generation, end-user contracts, DSO regulations, etc., may be designed in different ways. Currently, energy authorities offer little guidance on how impacts on the electricity system should be considered when such measures are designed.

In view of the uncertainty surrounding the future energy system, such guidance should be developed. In particular, energy authorities should provide general guidance on how the impact on demand and demand response and investments in peak and flexible generation capacity should be taken into account in the design of measures affecting energy use and generation, in order to avoid or reduce unnecessary adverse effects.

5. Design of grid tariffs.
Variable grid tariffs should reflect marginal grid costs, whereas residual tariffs should be designed to cover residual costs in an efficient way. Efficient recovery of residual costs imply that residual tariffs should affect consumption and generation as little as possible. In the Nordic

market, the generators pay parts of the residual grid costs in the form of a so-called G-tariff. A similar tariff is not imposed on generators in neighbouring markets. Hence, the G-tariff in the Nordic market may constitute a competitive disadvantage for Nordic generators compared to generators in other markets. In addition, the capacity-based Swedish G-tariff should be revised and harmonized with the G-tariffs in the rest of the market, as it constitutes a barrier to investments in peak and flexible capacity in Sweden. The efficiency of the current differentiation between bidding zones should also be reviewed.

Similarly, grid tariffs for consumers should be designed so that relevant price signals reach consumers and are not muted by ill-designed grid tariffs.

Incentives for both demand-side participation and investments in peak and flexible generation capacity should be strenghtened

Generally, there is probably sufficient peak and flexible generation capacity in the Nordic market to manage most situations in the next 15 years. In the short run it is probably cheaper to increase the contribution of peak and flexible capacity from generation than from demand. Hence, it is important to remove barriers to efficient investment and utilization of peak and flexible generation.

In order to avoid unnecessary cost increases in the future, however, utilization of flexible resources even on the demand side should be facilitated by removal of unnecessary barriers. *Inter alia*, measures to improve price formation in the Elspot market, revision of product definitions in the reserve markets, increased incentives for loads to be in balance, should cater for increased demand-side participation for customers with hourly metering. The scope for demand-side participation in today's market is probably relatively small, but we believe that it will take some more time for the demand side to become active in the market. Hence, it is important to prepare for a future where demand-side participation may become crucial and profitable.

In order to utilize resources on the supply and the demand side efficiently, market participants must face correct price signals, including hourly price variations, locational prices, and flexibility pricing. In addition, the demand side must have the opportunity to participate in the market.

Recommendations: Prioritized measures

Our analysis reveals several measures that would strengthen price formation and cost recovery in the Nord Pool market area, although in general, the market is highly liquid and well-functioning. Due to the maturity and high degree of efficiency, it is not possible to identify one or two main measures. Rather, we suggest a menu of adjustments and improvements that together could make a significant difference for future capacity adequacy. Some of the measures can be implemented in the short term, whereas other measures should be assessed and developed further. There is also a need for harmonization and common guidelines in some areas. The following measures should be high on the priority list.

Short-term measures: Concrete measures in the short term include removal of barriers to investments in peak and flexible capacity in the grid tariffs, set clear rules for the TSOs calculation of interconnector capacity made available to the market, and make sure that the imbalance settlement yields equal incentives for generation and demand to be in balance. The pricing of Elspot activation of the peak load reserve in Finland and Sweden should be reviewed, to assess whether it constitutes a barrier to demand flexibility in the market. Moreover, the adequacy of the remuneration for system services should be assessed, and whether product definitions should be revised in order to facilitate valuable contributions from the demand side. Finally, general guidelines for how different authorities should consider system and capacity adequacy effects (including flexibility) in the design of policy measures and regulations that affect electricity supply and demand. This is for example relevant when energy efficiency measures in different sectors are designed.

Medium-term measures: It is important to facilitate efficient exchange of reserves between the countries through harmonization of product definitions and development of models for efficient allocation of interconnector capacity between exchange in Elspot and reserve markets. This should increase the value of flexible resources. Flow-based market coupling, 15-minute time resolution and the bidding zone delimitation could strengthen Elspot market signals and increase trade in Elbas. Hence, the future market design should be developed with these considerations in mind. The countries in the Nord Pool areas do not have a common framework for capacity adequacy assessment. Such a common framework should be developed.

Long-term measures: Flow-based market coupling, possibly in combination with new bidding zone delimitation and 15-minute time resolution, should probably be implemented. The design should be based on a thorough assessment of the design elements. Most countries will probably support renewable generation even after 2020. Thus, it is important to make sure that the support schemes are designed in a way that does not yield adverse price effects and increased system costs.

1. Introduction

1.1 Background

Security of supply, or capacity adequacy, in the power system depends on the market's ability to provide sufficient energy and effect capacity in all situations. The energy transition threatens to weaken capacity adequacy in the power sector, as flexible and controllable generation capacity is being increasingly replaced by inflexible and intermittent capacity as part of the efforts to reduce greenhouse gas emissions. The increase in subsidized renewable generation capacity erodes the profitability of conventional power generation. The demand for flexibility in the system increases, while the supply of flexibility decreases.

This has led to a concern for the future ability of the generation capacity to cover demand in all situations. In order to improve the economics of flexible generation capacity and secure capacity adequacy, several European countries are in the process of implementing, or discuss to implement, separate capacity markets or mechanisms. Other changes in the market design may however, also improve the investment incentives, even in the Nordic power sector.

The Nordic markets are strongly integrated through interconnectors and the common Nordic power exchange. Capacity challenges are rarely isolated to one Nordic country. It is therefore natural to assess the capacity adequacy outlook and possible remedies to capacity adequacy challenges from a common Nordic perspective.

1.2 Problem statement

The following problem statement summarizes the objective of the study presented in this report:

> What market solutions may be used to manage capacity adequacy in the Nordic market, and how could an efficient transition to adequate market solutions be achieved?

The project is to provide concrete recommendations on effective market based measures to stimulate capacity adequacy in the Nordic region. The focus is on the potential of other market solutions than separate capacity markets and mechanisms.

The analysis is limited to an assessment of capacity adequacy in the Nordic power market (Denmark, Finland, Norway, Sweden and the Baltic states) within the framework of the integrated North West European power market, which includes Germany, Poland, the Netherlands and Great Britain. The time perspective of the analysis is 2015–2035.

The analysis is divided into 6 parts presented in separate chapters in the report:

Chapter 2 defines capacity adequacy and the capacity adequacy challenge, including different approaches to capacity adequacy assessment.

Chapter 3 provides an overview of current measures for handling of capacity adequacy, and a brief description of the development of capacity adequacy in the Nordic area and how occurrences of capacity shortages have been handled.

Chapter 4 presents existing scenarios for future market developments, including an analysis of different factors that affect capacity adequacy, in the Nordic area, and a simplified model analysis of the probability of a generation gap in the Nord Pool market area in 2030.

Chapter 5 discusses the generation gap in accordance with the EC checklist, i.e. assesses the generation gap and analyse possible market measures to manage capacity adequacy in the Nordic and Baltic market context.

Chapter 6 presents a summary of the recommendations from the study.

2. Relevant Definitions

In order to analyse capacity adequacy in the Nordic context, we need to define the issue in more detail. The definition may be based on academic literature, guidelines and empirical studies, and cases of inadequate capacity adequacy experiences in the Nordic market.

2.1 Definitions of capacity adequacy

In this section, we give an overview of some of the literature on capacity adequacy. How is the issue defined and what factors contribute to capacity adequacy? Moreover, we describe how the concept is translated into an operational definition in different markets.

2.1.1 Capacity adequacy and capacity shortage

Capacity adequacy depends on the ability of the system to balance generation and consumption in real-time. In essence, capacity adequacy may be defined as the capability of the electricity system to keep the lights on at every moment. Historically, the concept has been associated with sufficient generation capacity to meet *peak demand*. For example, the US federal regulator, FERC, uses the following definition: "To maintain reliable operations, electric systems must maintain sufficient capacity resources to peak load requirements plus a planning reserve margin."[1] The planning reserve margin is necessary as a contingency resource in order to handle forecast errors and disturbances in real-time.

The flipside of capacity adequacy is *capacity shortage*: We want capacity adequacy in order to avoid curtailment. Capacity shortage is "a situation where available generation capacity and imports together are insufficient to serve demand without violating the constraints of the grid, keeping satisfactory reserve levels" (Doorman *et al.*, 2004). This definition of capacity shortage highlights even the access to electricity

[1] Staff report, U.S. Federal Energy Regulatory Commission, Docket AD13–7–000, August 14, 2013.

imports and the adequacy of the grid as important for capacity adequacy. Doorman *et al.* (2004) also point out that a capacity shortage may show up either in the day-ahead market, in real-time operation or both. Hence, we may distinguish between the market's ability to provide sufficient capacity in the day-ahead timeframe, and the system's ability to provide sufficient reserves.

Hence, we may think of capacity adequacy in terms of market equilibrium and in terms of real-time operation. The (day-ahead) market solution is essentially a plan for demand and supply for each hour the next day. In order for the market to function, we need to equate supply and demand for every hour. In addition, we need reserves in order to handle forecast errors and disturbances. In this report, we use the following definition:

> Capacity adequacy is the system's ability to establish market equilibrium in the day-ahead market, and at the same time provide adequate balancing resources for real-time operation, even in extreme situations.

This definition differs from the FERC definition on two accounts: It is not limited to peak load situations, and it includes the market's ability to equate supply and demand. The definition implies that we should not limit capacity adequacy to peak load situations, and that we may distinguish between capacity adequacy in the market (day ahead planning) and in real-time operation.

Capacity adequacy has a longer-term planning dimension as well. Although we usually define capacity adequacy as a short-term concept, the focus of *capacity adequacy assessments* is often the system's ability to provide capacity adequacy *in the future*. Hence, capacity adequacy assessments include forecasting *the market's ability* to provide adequate capacity *investments*, in addition to forecasting a number of other market developments such as the growth in electricity consumption, investments in generation and transmission capacity, decommissioning, etc.

The overriding objective of the market and regulatory design should be to provide capacity adequacy in a cost-efficient manner, employing all available resources and ensuring that these resources are adequately compensated for their contribution, via the market or regulatory measures.

2.1.2 *Capacity adequacy in the market*

We define capacity adequacy *wider* than in the technical sense of "keeping the lights on in real-time". Our definition takes the actual market design into account. The market design implies that the real-time balance is achieved step-wise:

- Forward markets signal long-term prices to which supply and demand may adjust.
- Day-ahead market bids and offers represent the ability and costs associated with different levels of supply and demand.
- The intraday market offers opportunities to handle deviations from the day-ahead market solution due to forecast errors and contingencies that appear after gate closure in the day-ahead market and prior to gate closure in the intraday market.
- TSOs manage real-time (within the hour) deviations due to within the hour variations (structural imbalances) and forecast errors and contingencies not handled in the intraday market.

The day-ahead market is in essence a forward market (albeit short term), and deviations from the day-ahead market solution will occur in real-time. Such deviations may be handled by market agents' trading in the intraday market, or by the TSO in real-time. Forecast errors may appear and contingencies occur at any time between closure of the day-ahead market and real-time.

However, even if the market agents handle all deviations from the hourly day-ahead market solution in the intraday market, the TSO needs access to balancing reserves. The reason for this is that the day-ahead market operates as if demand (and supply) is stable within each hour, which it is not. In order to handle planned and unplanned deviations in real-time, the TSOs must have access to reserves for balancing within the hour.

As mentioned, capacity shortages may occur in the day-ahead market, in real-time or both. Capacity shortages may for example occur in the day-ahead market if all flexibility in the system is not reflected in the market bids. Then, depending on the market design, flexible resources may be activated in the intraday time-frame or in the reserve market in order to ensure balance between supply and demand in real-time. Similarly, the day-ahead market may be able to establish equilibrium between supply and demand, but at the expense of the provision of sufficient reserves for real-time operation. One design element that affects the likelihood of where capacity shortages occur is the timing of reserve procurement by the TSO – prior to or after closure of the day-ahead market.

Other design elements such as the market access for loads and the balancing responsibility of different actors are likely to affect capacity adequacy as well.

2.1.3 Three main aspects of capacity adequacy

The question of the system's ability to keep the lights on at every moment may not only be associated with peak load situations, but even with the system's ability to provide the right types of capacity in terms of energy, and energy and effect flexibility. In the future electricity system, increased intermittent and highly volatile generation capacity and increased trade may induce faster, larger and less predictable changes in flows than before. Moreover, controllable base load and flexible capacity may increasingly be replaced by less controllable or uncontrollable, weather-dependent generation. The reduced controllability of the generation capacity means increased demands on the flexibility of the system, in order to handle fast changes and provide sufficient back-up energy for prolonged periods of low wind (and solar) generation.

Our approach to the long-term outlook for capacity adequacy is in line with ENTSO-E, which outlines three main aspects of capacity adequacy (ENTSO-E, 2014):

- Peak load: Do we have sufficient capacity (including demand response) to handle peak load situations?
- Flexibility: Is the capacity (including demand) sufficiently flexible to handle variations in load and balance the system in real-time?
- Energy back-up: Do we have sufficient energy back-up capacity to serve demand during prolonged periods of low wind and solar generation?

We note here that the role of the different markets and reserves may be different when it comes to providing the different aspects of capacity adequacy.

In addition, capacity adequacy has a geographical dimension. As indicated by the definition in Doorman *et al.* (2004), we should also consider the import capacity when assessing capacity adequacy within a control area or a region. Moreover, the geographical dimension should not be limited to import capacity across national borders, but take into account relevant bottlenecks in the internal transmission grids as well.

Peak load capacity margin

At any time, electricity consumption including losses cannot be larger than generation. If generation is not sufficient to cover consumption, blackouts or curtailment will occur. Blackouts happen if the system operator is not able to contain the situation, and is typically associated with accidents and trips. If a gap is identified prior to real-time operation, e.g. based on the day-ahead market solution, the system operator will have time to implement measures to handle the situation through curtailment. Curtailment may be voluntary, according to contracts or obligations, or imposed. In the first case, the curtailed loads will be eligible for compensation. In the second case, compensation may or may not be paid.

Depending on the demand flexibility *in the market*, the capacity shortage may "show up" as very high prices in the day-ahead market or in the intraday market. In essence, high prices may induce a kind of curtailment of loads, but in this case, loads volunteer to reduce consumption at the price levels reflected in their market bids.

Increased shares of renewable generation in the power system are likely to imply that the need for operating reserves increases, for several reasons:

- Increased probability of forecast errors: It is more difficult to forecast day-ahead supply.
- Increased magnitude of forecast errors: The deviations within the operating hour (planned and unplanned) may increase.

Hence, the required reserve margin may increase, leaving, all else equal, less capacity for day-ahead market trade.

Flexibility

When demand, including imports and exports, and/or intermittent, weather-dependent generation changes rapidly, the rest of the system needs to be flexible in order to handle the fluctuations. Here, time is of the essence: we need capacity (load) that is capable of starting or ramping up generation (reducing consumption), or closing or ramping down generation (increasing consumption), sufficiently fast. We may distinguish between slow and fast reserves, and define fast reserves as more flexible than slow reserves. Predicted changes in loads may be handled by slow reserves, whereas unpredicted and fast changes must be handled by fast reserves. Again, we need flexibility both in the day-ahead market and in real-time operation.

Fast reserves may provide slow balancing as well, but are usually more expensive and may not be able to generate continuously for longer periods. Hence, deviations and fast changes handled by fast reserves will usually be replaced by slow reserves as soon as possible. The need for fast and slow reserves is thus determined by the characteristics of the system, i.e. the frequency and magnitude of variations in residual demand.

Increased shares of intermittent generation in the system are likely to increase the need for fast reserves.

Energy back-up capacity

With large shares of wind and solar generation in the system, prolonged periods of low generation may result. If such periods coincide with periods of high demand, such as cold spells during winter, energy backup may be necessary. Even if there is access to sufficient capacity (and demand flexibility) in the system to handle short-term peak load and flexibility challenges, these resources cannot necessarily be employed to handle energy shortages. Reserve capacity may not be able to provide sufficient energy generation, and energy flexibility on the demand side may be reduced if consumers have less access to alternative sources of heating.

2.2 Capacity adequacy assessment

Based on the definition of capacity adequacy and the multiple aspects of capacity adequacy, we may say that capacity adequacy requires that

- we have sufficient capacity in MW to cover peak demand
- that the MWs are sufficiently flexible (to provide slow and fast reserves)
- that the MWs are capable of providing sufficient MWh over a prolonged period (energy back-up).

When we talk about capacity adequacy, we think of the system's ability to handle extreme situations that by nature occur relatively seldom. It is difficult, if not to say prohibitively costly, to construct a system in which loads are not ever lost. Hence, capacity adequacy is not associated with a zero probability of curtailment of demand. In order to assess whether the capacity is adequate, we must define what we mean by "sufficient" or "adequate" capacity, i.e. a reliability standard. We describe different ways of defining reliability standards in the next section.

2.2.1 Reliability standards

Loss of Load Expectation

The regulator in GB, Ofgem, defines capacity adequacy in terms of a Loss of Load Expectation (LOLE) (Ofgem, 2013). LOLE expresses "the number of hours per annum in which, over the long-term, it is statistically expected that supply will not meet demand."

The GB LOLE is set to 3 hours per year, which is the same as the reliability standard in France. The reliability standard in Netherlands is a LOLE of 4 hours per year, whereas it is 8 hours per year in Ireland. LOLE is also used in the US markets PJM and ISO-NE.

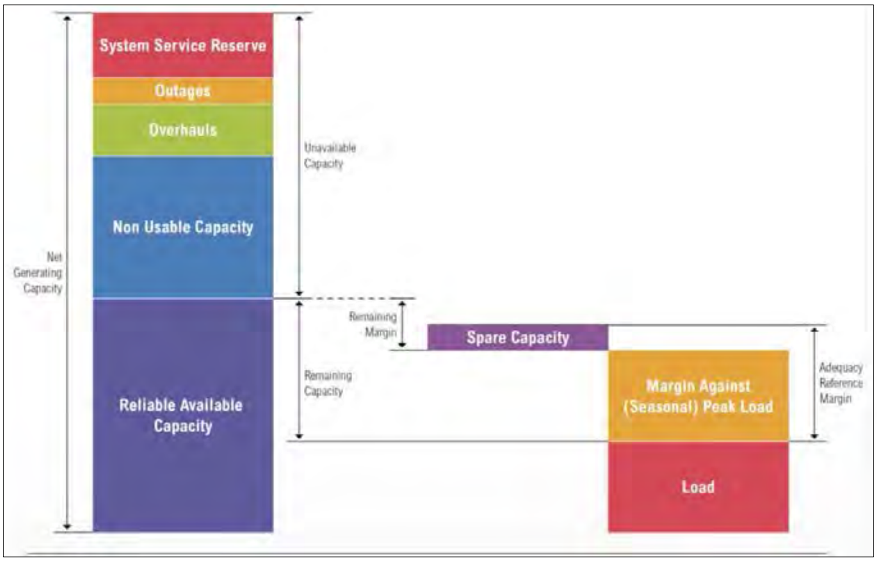
The reliability standard may also be set according to the Expected Energy Unserved (EEU), i.e. a calculation of the MWh "that is expected not to be met by generation in a given year."

De-rated capacity margin

An alternative to the LOLE approach is to define the reliability standard in terms of a de-rated capacity margin, i.e. "the amount of excess supply above peak demand". De-rating means an assessment of the reliability of the existing capacity to take into account the expected availability of plants during peak demand. For example, wind power is likely to be strongly de-rated as wind power generation is not or only weakly correlated with demand.

In its Scenario Outlook and Adequacy Forecast 2011–2025 (SOAF), ENTSO-E used the de-rated capacity margin approach, see Figure 2.1.

Figure 1. De-rated capacity margin methodology



Source: ENTSO-E (2011).

Ofgem does not recommend to use the de-rated capacity margin as the basis for determination of a reliability standard. The main reason is that the de-rated capacity margin is a measure of the average or mean capacity situation, and does not include a variation around the average or mean value, i.e. does not take the probabilities and co-variation of events into account. Ofgem notes that "the de-rated margin was an appropriate indicator at times where intermittent generation was not significant and the proportion of each type of generation in the fleet was roughly constant year on year".

Risk of unwanted situations

Doorman *et al.* (2004) define the vulnerability of the system as the *risk* of experiencing *unwanted situations*. Unwanted situations are:

- High prices, defined as abnormally high prices over a sustained period.
- Curtailment, defined as planned reductions in demand other than through market prices.
- Blackouts, defined as unplanned and uncontrolled outages of major parts of the power system.

The “reliability standard” proposed by Doorman *et al.* (2004) includes probability in the definition, and highlights that the desired level of capacity adequacy depends on society’s willingness to accept incidents of high prices, curtailment and blackouts.

2.2.2 European Commission checklist for intervention

All of the definitions of capacity adequacy presented above imply that an assessment is made of the system’s ability to provide sufficient capacity in the future. An alternative approach is to assess to what extent the market is able to provide adequate price signals (and revenues) in order to produce the required capacity. This approach explicitly takes the market prospects and market design into account. The philosophy is that if an adequate market framework is in place, then the market can be relied upon to produce sufficient and relevant capacity. Before direct intervention in the market mechanism is considered, one should investigate the existence of market failures and the potential impact of removal of these.

In its guidelines on public intervention (EUC 2013b), the European Commission presents a checklist for assessment of the risk of a future generation gap (EC checklist). The EC checklist includes an assessment of the extent to which market barriers or market failures may be the cause of capacity adequacy concerns.

The checklist implies that assessments of future capacity adequacy should:[2]

- Identify what kind of capacity is needed, i.e., peak load capacity vs. flexible capacity.
- Take into account the *value* of lost load.
- Assess the profitability of generation capacity: What is the market expected to provide in terms of investments, decommissioning and refurbishments?
- Take into account the potential for demand response. What barriers to demand response may exist?
- Take into account interactions with neighbouring member states and the impact of the internal energy market.

[2] Appendix 1 presents the checklist in full.

- Assess regulatory or market barriers: To what extent may missing investments be explained by market design or regulatory barriers? Possible regulatory or market barriers include:
  - Retail price regulations.
  - Wholesale price regulations and bidding restrictions.
  - Ill-designed renewable support mechanisms.
  - Impact of existing support schemes for fossil and nuclear generation and maintenance/refurbishment of existing generation capacity on investments.
  - Ineffective intraday, balancing and ancillary service's markets.
  - Market concentration.

2.2.3 Summary and our position

We agree with Ofgem that the de-rated capacity margin is not a suitable measure of capacity adequacy in today's market. Rather, a probabilistic approach should be adapted when assessing the future capacity adequacy, capturing the probability of the simultaneous occurrence of different aspects. Moreover, the wider market context needs to be taken into account, e.g., interconnections and import opportunities, and the correlation between different interconnected markets.

In addition, a reliability standard in terms of LOLE or EEU should be determined in terms of an acceptable probability of curtailment of demand. The reliability standard should be determined in relation to the capacity adequacy assessment methodology. Ofgem states for example that a LOLE implying curtailment in, on average, 3 hours per year, does not imply that one should expect curtailment to occur, on average, for 3 hours per year. Hence, this LOLE may be attributed to a day-head market solution not being established in on average, 3 hours per year, in which the situation is resolved in the intraday or reserve markets, or that the situation will be resolved by other market dynamics not represented in the model used for the LOLE assessment.

Model analysis and capacity forecasts should not be the only element in capacity adequacy assessments. It is equally relevant to include aspects such as the ones included in the EC checklist, i.e., to assess the ability of the market to provide adequate capacity and flexibility.

Hence, a full capacity adequacy assessment should include:

- A model-based probabilistic approach to identify crucial elements of capacity adequacy.
- An appropriate definition of a reliability standard based on that approach.
- An assessment of the markets' ability to provide capacity adequacy.

3. Current situation and historical evidence

In this chapter, we describe how the balance between demand and supply is established and maintained in the current Nordic system, and we provide an overview of experience with capacity shortage in the Nordic market, including the role of demand response in the market.

3.1 Current measures

In essence, the capacity balance in the Nordic and Baltic area is established via the market place and via administrative measures. In the market place, the balance is provided by trading between market participants, while administrative measures imply that authorities, including system operators as regulated entities, are responsible for the outcome. The administrative measures may be implemented by use of market-based mechanisms, however. From an administrative perspective, one might say that a large part of the planning of the system balance up to real-time is entrusted to the market participants, while the momentary balance is the responsibility of the authorities, i.e., the TSOs by delegation.

Market players earn revenues for capacity in the day-ahead market, the intraday market and the reserve markets, including by procurement of or remuneration for ancillary services. In addition, revenues may be hedged using long-term contracts, which may be bilateral or brokered forward contracts.

3.1.1 *Spot markets*

The spot markets include the Elspot market and the Elbas market.

The day-ahead market, Elspot, is the largest market place in the Nordics with a market share of 84% (2013).[3] This market is cleared at noon the day before operation. The players may adjust their commitments in the day-ahead market in the intraday market, Elbas, which closes one hour prior to real-time. In 2013, the market turnover was 493 TWh in Elspot and 4.2 TWh in Elbas. The share of Elbas trade is low compared to the share in e.g. Germany. Among the Nordic countries, the share has historically been particularly small in Norway (Scharff and Amelin, 2015). Scharff and Amelin (2015) suggest that the reason is that Norway joined the Elbas market late (2009), have earlier gate closure,[4] and a very high share of hydropower generation.

Well-functioning market places are an important basis for the provision of capacity adequacy, as investments are based on price expectations. If the market expects a future capacity shortage, forward prices should increase and strengthen the incentives to invest in new capacity. The short-term price formation is crucial as well. In the day-ahead market prices will vary to reflect the hourly capacity balance, with prices being higher in hours with a small capacity margin and lower in hours with a larger capacity margin. Flexible capacity may exploit their flexibility by varying generation levels according to hourly variations in day-ahead prices, by providing flexibility in the intraday market and by supplying balancing reserves. Hence, the expected prices in all market timeframes are relevant for investment decisions.

Similarly, investments affecting demand should take into account expected future prices, including price variations and the value of flexibility in different timeframes. Relevant investments on the demand side include heating solutions, energy efficiency measures and choice of electrical equipment.

The important aspect is that capacity adequacy cannot be viewed independently of market developments and expectations. Well-functioning markets should contribute to capacity adequacy by affecting decisions on the supply as well as the demand side.

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[3] http://www.nordpoolspot.com/message-center-container/nordicbaltic/exchange-message-list/2014/Q1/No-22014–2013-another-record-year-for-Nord-Pool-Spot-/

[4] In 2013, the gate closure in for Norwegian Elbas trade was moved to one hour before delivery, in line with the gate closure in the other market areas.

As in other markets, however, shortages are likely to occur. Since the real-time balancing of the system is crucial, various administrative or regulatory mechanisms are put in place as back-up – should the markets fail to reach equilibrium – and to handle deviations and contingencies.

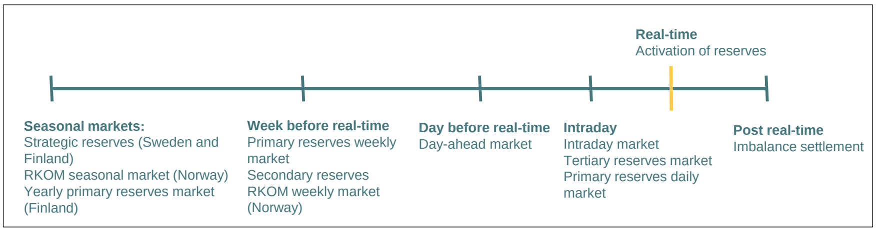
3.1.2 Reserve markets

The Nordic reserve markets are described in Table 1 and the clearing order of the physical markets is shown in Figure 2. Primary reserves are activated automatically in order to stabilise the frequency in the system. Secondary reserves are activated in order to restore the frequency to 50 Hz. Finally, tertiary reserves are activated if needed, and replace the activated primary and secondary reserves. The pricing in the reserves markets is based on weekly, daily or hourly auctions, using marginal pricing. The TSOs also procure reserves through bilateral agreements.

Table 1. Reserves markets in the Nordic region

	Activation procedure	Response time	Market solution
Primary reserves	Automatic feedback-control based on frequency	Zero	FCR-N and FCR-D: markets for capacity to primary reserves. Daily and weekly markets with hourly or load block resolution
Secondary reserves	TSO controls units	Max 210 seconds	FRR-A: Market design under development for the Nordic synchronous area LFC: Market in Western Denmark
Tertiary reserves	Manually activated	Max 15 minutes	FFR-M: Hourly market for energy, separate markets for ramping up and ramping down, market closes 45 minutes before real-time RKOM (Norway): Option market for TSO: generators and consumers commit to bid volumes into FRR-M (weekly and seasonal resolutions), only used during winter (see Section 3.1.4)

Figure 2. Clearing order of physical markets



There is no discrimination between generation and demand in the regulation or product definitions in the reserve markets in any of the Nordic countries. Traditionally, generation has contributed more to the reserve markets than the demand side. However, in recent years, the demand side participation in the reserve markets has increased. The Finnish TSO has worked actively to increase the demand sides participation in reserve markets, which has resulted in 100–300 MW of tertiary demand side reserves and 70 MW of primary demand side reserves according to the Finnish TSO, Fingrid. Also the Swedish TSO, SvK, has been working actively to increase the demand side participation in the reserve markets, with a main focus on tertiary reserves.

The Nordic TSOs have a coordinated solution for load following, which gives the TSOs the opportunity of moving generation ramping by up to 15 minutes.[5] The generator is compensated for the losses associated with the load following. Statnett is introducing a new production smoothing service for flexible generation with frequent fluctuations larger than 200 MW in July 2015.[6] The new service aims at reducing structural imbalances (see Section 4.2), and gives Statnett an opportunity to move generation ramping by up to 30 minutes. The generator receives a fixed administrative compensation (around 20,000 EUR/year) and a variable tariff (around 0.5 EUR/MWh). Additionally, the generator is compensated for energy deviations by the best of the day-ahead price and the tertiary reserves price.

3.1.3 Imbalance pricing

In order to participate in the electricity market, a balance responsible party (BRP) is liable for any deviations from the party's market obligations. A BRP that causes deviations from his spot market commitments is penalised by an imbalance cost. This penalty is paid to the TSO who incurs costs in order to handle the imbalance. The TSO must activate the cheapest available offers for tertiary reserves to handle deviations. The price of tertiary reserves is determined by the bids of the providers. The imbalance price is set by the price in the tertiary reserve market.

The imbalance settlement in the Nordic region is designed such that consumers have a weaker incentive to be in balance than generators do.

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[5] http://www.statnett.no/Drift-og-marked/Systemansvaret/Systemtjenester/Lastfolging/
[6] http://www.statnett.no/Global/Dokumenter/Kraftsystemet/Systemtjenester/Produksjonsglatting%20-%20vilk%C3%A5r%20050215.pdf

The pricing rules for tertiary reserves and imbalances are summarised in Table 2. The price offered by a provider of tertiary reserves must be better than the zonal day-ahead price. This results in a non-negative penalty for generators who cause an imbalance, relative to the day-ahead price. A party that faces imbalances may therefore try to adjust its commitments in the intraday market, if possible, because this may be cheaper than receiving the imbalance price.

Table 2. Pricing rules in the tertiary reserves auction

	Provider of tertiary reserves (participating in the hourly auction)	**Generation imbalance price**	**Consumption imbalance price**
Upward ramping	System deficit: Ramp up generation or ramp down consumption Bid price must be above the zonal day-ahead price	Lower generation than obligations Pays the upward ramping price (higher than or equal to the day-ahead price)	Higher consumption than obligations Pays the consumption imbalance price (equal to the provider's price in the dominating direction)
Downward ramping	System surplus: Ramp down generation or ramp up consumption Bid price must be below the zonal day-ahead price (i.e., the provider receives a positive premium if activated)	Higher generation than obligations Receives the downward ramping price (lower than or equal to the day-ahead price)	Lower consumption than obligations Receives the consumption imbalance price (equal to the provider's price in the dominating direction)

The imbalance cost for consumption is on average lower than that of generation. If a consumer faces an imbalance that is in the opposite direction of the dominating direction,[7] the consumer receives the imbalance price in the dominating direction. However, a generator receives the day-ahead price (resulting in a higher penalty). Hence, the generator has a stronger incentive to stay in balance – relative to the day-ahead obligations – than that of consumers.

The following examples illustrate the difference in imbalance settlement for generation and consumption. Assume that the day-ahead zonal price (spot) is 100 EUR/MWh, and that a generator has a day-ahead market obligation of 100 MW. Then the imbalance settlements in four cases are shown in Table 3.

[7] By dominating direction, we mean the direction (system deficit or system surplus) with the highest activation of tertiary reserves.

Table 3. Imbalance settlement examples for a generator

	Dominating direction	Tertiary reserves price	Actual generation	Generator imbalance	Imbalance settlement
1	System deficit	Up: 110 EUR/MWh Down: 100 EUR/MWh (spot)	110 MW	Surplus: +10 MW	Receives 10 MWh x 100 EUR/MWh = 1,000 EUR
2	System deficit	Up: 110 EUR/MWh Down: 100 EUR/MWh (spot)	90 MW	Deficit: – 10 MW	Pays 10 MWh x 110 EUR/MWh = 1,100 EUR
3	System surplus	Up: 100 EUR/MWh (spot) Down: 90 EUR/MWh	110 MW	Surplus: +10 MW	Receives 10 MWh x 90 EUR/MWh = 900 EUR
4	System surplus	Up: 100 EUR/MWh (spot) Down: 90 EUR/MWh	90 MW	Deficit: – 10 MW	Pays 10 MWh x 100 EUR/MWh = 1,000 EUR

Now, assume the same situation for a consumer. The imbalance settlement for the consumer in the same four cases are shown in Table 4.

Table 4. Imbalance settlement examples for a consumer

	Dominating direction	Tertiary reserves price	Actual consumption	Consumer imbalance	Imbalance settlement
1	System deficit	Up: 110 EUR/MWh Down: 100 EUR/MWh (spot)	90 MW	Surplus: +10 MW	Receives 10 MWh x 110 EUR/MWh = 1,100 EUR
2	System deficit	Up: 110 EUR/MWh Down: 100 EUR/MWh (spot)	110 MW	Deficit: – 10 MW	Pays 10 MWh x 110 EUR/MWh = 1,100 EUR
3	System surplus	Up: 100 EUR/MWh (spot) Down: 90 EUR/MWh	90 MW	Surplus: +10 MW	Receives 10 MW x 90 EUR/MWh = 900 EUR
4	System surplus	Up: 100 EUR/MWh (spot) Down: 90 EUR/MWh	110 MW	Deficit: – 10 MW	Pays 10 MW x 90 EUR/MWh = 900 EUR

The consumer receives more than the generator in case 1, and the consumer pays less than the generator in case 4. That is, the imbalance price differs when the party helps the system, meaning that the deviation acts to mitigate the system imbalance. A consumer who helps the system receives a better price, compared to a generator. The settlements are the same for the generator and the consumer in case 2 and 3. Thus, on expectation, the consumer faces a smaller imbalance price. If we assume that the probability of each event is the same, the generator faces an expected imbalance cost of -50 EUR/MWh in the case of imbalances, whereas the consumer's expected imbalance cost is zero. Hence, if the probabilities of a surplus and a deficit are equal for a consumer, and the premiums in each direction of the tertiary reserves market are the same, the consumer has no incentive to avoid deviations from the day-ahead obligations.

The example also illustrates that generators have a stronger incentive to provide tertiary reserves, rather than being in imbalance. E.g., if there is a system deficit and a producer has additional generation capacity, the producer would receive a higher price from participating in the tertiary reserves auction, compared to receiving the imbalance price. A consumer with flexibility will receive the tertiary reserves price when deviating from its day-ahead obligations, regardless of whether the consumer participated in the tertiary reserves auction or not.

Table 5Table shows that the distribution of activated tertiary reserves are approximately equal in the two directions (upwards and downwards). However, Table 6 shows that the premiums (i.e., the difference between the day-ahead price and the tertiary reserves price) in the two directions are not equally distributed. The premium in the upwards ramping direction (system deficit) is typically higher in capacity constrained bidding zones (DK2, FI, NO3, SE3, SE4). Furthermore, there are occasional premium peaks in the upwards direction (system deficit) in these bidding zones, as shown in Figure 3. Thus, a consumer may have an incentive to avoid large deficits, because the imbalance penalty is large for consumption deficits when the tertiary reserves premium is high.

Table 5. Share of hours with activation in the tertiary reserves market in 2014 (per cent)

Direction	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
Up	29%	15%	24%	12%	24%	14%	14%	29%	23%	32%	23%	3%
Down	24%	13%	30%	9%	27%	15%	19%	30%	35%	42%	27%	4%

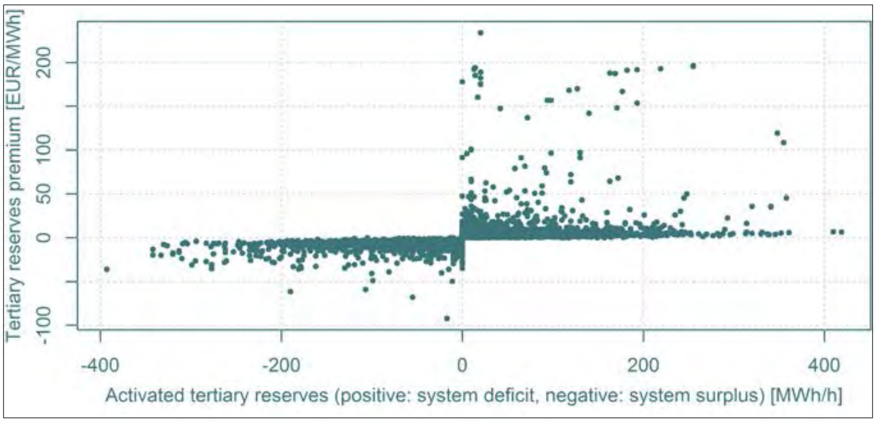
Source: Nord Pool Spot.

Table 6. Average premiums in the tertiary reserves market in 2014 (EUR/MWh)

Direction	DK1	DK2	FI	NO1	NO2	NO3	NO4	NO5	SE1	SE2	SE3	SE4
Up	10.9	18.2	14.9	5.3	4.8	14.5	9.9	4.3	7.7	6.5	9.0	46.0
Down	9.2	9.6	11.2	6.6	5.8	7.6	8.1	5.5	6.6	6.4	7.4	13.7

Source: Nord Pool Spot.

Figure 3. Activated tertiary reserves versus the premium in tertiary reserves market for Stockholm region (SE3) in 2014



Source: Nord Pool Spot.

The imbalance penalty for consumption surplus may also be very large in certain situations. NVE (2010b) points at two hours with high loads in December 2009, with day-ahead prices were around 12 NOK/kWh, and imbalance prices around 1 NOK/kWh. Suppliers who had a positive imbalance (lower than assumed consumption), faced a cost of about 11 NOK/kWh (about 1,400 EUR/MWh) for their surplus, which was never consumed. Thus, a supplier has an incentive to be in balance in this case, but our example shows that the incentive for a supplier/consumer to stay in balance is weaker than that of generators.

3.1.4 Strategic reserves and capacity payments

In Finland and Sweden, the strategic reserves or peak load reserves (PLR) are the main mechanism to handle capacity shortages when the Elspot market fails to equate supply and demand. The PLRs in Sweden and Finland currently consist of 1,500 and 365 MW, respectively (cf. Fingrid, SvK). The PLR may consist of both generation capacity and demand response. Whereas generation capacity in the PLRs cannot be bid in Elspot, demand response in the PLR may be active (bid) in Elspot. If the Elspot market fails to establish equilibrium, generation reserves are bid into the day-ahead market and the tertiary reserve market.[8] The bidding rules for the PLRs are harmonised, and the TSOs aim

[8] If the Elspot algorithm fails to equate demand and supply, the strategic reserve is added and a new equilibrium calculated. The remaining PLR capacity is made available in the tertiary reserve market.

to minimise the market impact from the reserves. Therefore, it is required that bids from the PLR shall always be higher than the highest market bids in Elspot.

Denmark does not have a strategic reserve, but is planning to implement a reserve of 300 MW in Eastern Denmark from 2016.[9] The design of the Danish reserve is planned to be the same as for the Swedish and Finnish reserves.

Norway does not have a similar reserve. However, The Norwegian TSO, Statnett, has had two mobile gas turbines (300 MW) in a region (within, but not including an entire bidding zone) in Norway where there is a risk of energy shortage. The gas turbines were originally reserved for energy back-up in situations where the risk of rationing is larger than 50%, conditional on approval from the energy regulator, NVE. In essence, the reserve gas turbines were a grid measure, and not a market measure in the same sense as the PLRs in the other Nordic countries. However, Statnett has recently suggested to sell the mobile gas turbines, after start-up of the new transmission line which will reduce the risk of rationing in the area.[10]

In Norway, actors with flexible generation or consumption may commit capacity to the tertiary balancing market, through the "Regulerkraftsopsjonsmarked" (RKOM). RKOM functions as a (relatively short-term) capacity mechanism in Norway. Statnett procures RKOM capacity through a seasonal auction and a weekly auction, in order to secure adequate tertiary reserves for the winter season. From 2014, RKOM was divided into two segments, one "high quality" segment and one "limited" segment. Bids in the former requires full flexibility, i.e., the provider may not have any restrictions with respect to duration or resting time. The "limited" segment is designed for consumers, and allows restrictions on duration and a resting time of up to eight hours. The demand side offers the majority of the volume in the seasonal RKOM market with limited quality (729 MW in 2014/2015). There are no requirements to what price the provider should set in the tertiary market, other than that the price should be "economically efficient". That is, the bid price should reflect the marginal cost of the provider.

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[9] http://energitilsynet.dk/fileadmin/Filer/Internationalt/Hoeringer/Strategic_reserves_in_Eastern_Denmark_v_1.pdf

[10] http://www.statnett.no/Media/Nyheter/Nyhetsarkiv-2015/Nye-nettanlegg-gir-besparelse-og-bedret-forsyningssikkerhet/

In the 2014/2015 season, a total of 20 MW of high quality and 729 MW of limited quality RKOM reserves were procured in the seasonal auction at a price of 8 NOK/MW/hour (0.96 EUR/MW/hour) for both quality segments. A total of 1,700 MW of tertiary reserves are procured and covers dimensioning fault (1,200 MW) and unbalances in Norway. Moreover, at least 500 MW of the tertiary reserves should be of high quality, which is typically provided by generators. According to the TSO, consumers prefer the seasonal market to the auctions in shorter timeframes, due to the higher predictability and longer planning horizon.

Sweden has a goal to replace the strategic reserve by a market solution by 2020. The original plan was to gradually phase out all of the generation capacity from the strategic reserve to 2020, resulting in a reserve that consisted entirely of demand response. However, it has been challenging to increase the share of demand response. Currently, there is 626 MW (42%) of consumption in the Swedish PLR. SvK states that the requirements of continuous readiness and long-term commitments have made it difficult to increase the share of demand response in the reserve. The plan to phase out all generation capacity was therefore removed.

3.1.5 Other measures

Reduced grid tariffs for interruptible loads are offered in Finland and Norway. Statnett currently has 400–700 MW of capacity available as interruptible loads. The loads can be disconnected if there is a capacity shortage due to bottlenecks in the grid. In Finland, imbalance costs caused by the activation of interruptible loads are compensated.

In Sweden, there is a requirement set by the TSO on the DSOs' technical ability to remotely shut down consumption at large consumption sites (> 5 MW) in critical situations, i.e. if system reserves are inadequate.[11] If loads are disconnected, the TSO currently sets the compensation price to 20,000 SEK/MWh (about 2,150 EUR/MWh).

The Norwegian system is mainly constrained by energy, due to large share of flexible hydropower. The Norwegian TSO Statnett has had a number of administrative means for critical situations ("SAKS"), including defining new price zones, and cancel planned outages. However, Statnett has

[11] SvKSF 2012:01: Föreskrifter om ändring i Affärsverket svenska kraftnätsföreskrifter och allmänna råd (SvKFS 2001:1) om utrustning för förbrukningsfrånkoppling.

recently decided to terminate SAKS, after new investments in the grid.[12] Statnett may also exercise options for demand reduction, called "Energy options". During the winter of 2014/2015, Statnett has a volume of 392 MW of energy options available. Consumers who offer energy options commit to reduce consumption, subject to a notice of at least one week. The reduction must be available for at least two weeks. If the energy option is called, the consumer is compensated by an option premium and a redemption price. Statnett can only activate energy options if the probability of curtailment is larger than 50%. After the termination of SAKS, Statnett will only procure Energy options for mid-Norway.

3.2 Experience with capacity shortages

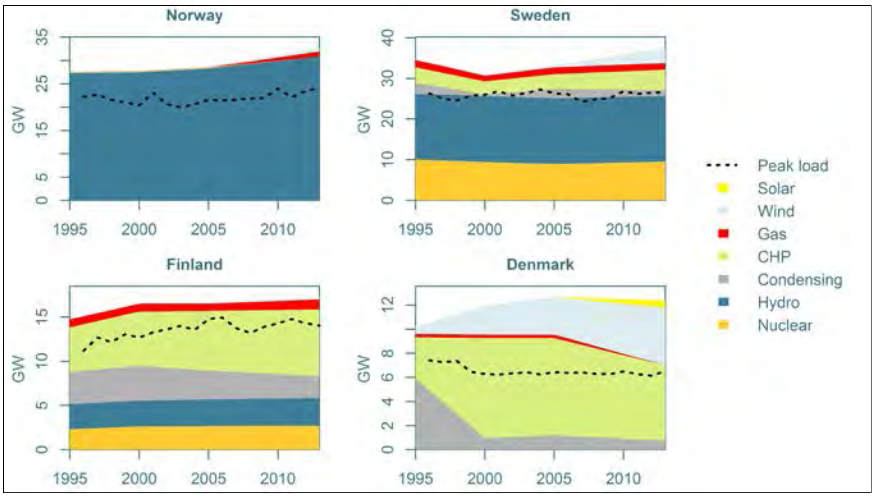
In the last 20 years, there have been few incidents with capacity shortages in the Nordic region. The installed capacity has increased somewhat, mainly, however, in the form of intermittent renewable capacity. Moreover, there has been some decommissioning of old condensing power and investments in conventional power generation over the period.

The capacity margin has remained strong in Norway and Sweden, due to a large share of flexible hydropower, and thermal generation in Sweden. Finland, however, has relied on between 2,000 and 3,000 MW of imports during its peak load hours in recent years. Denmark has experienced occasional capacity challenges due to the large share of wind power and combined heat and power (CHP) generation. In an interview, the Danish TSO, Energinet.dk, particularly points out periods during summer with low wind speeds, low heat generation, combined with maintenance on interconnectors and thermal plants, as challenging. The large share of wind power has been made possible due to ample interconnector capacity to Norway, Sweden and Germany. Hence, the Danish system is vulnerable to outages in multiple interconnectors.

Peak loads have stayed quite stable in recent years. Figure 4 shows the development in installed capacities and peak loads in each country. Peak load in Finland increased up to 2005, but has been stable since then. The peak load in Denmark fell somewhat between 1995 and 2000, and then stayed at a stable level.

[12] http://www.statnett.no/Media/Nyheter/Nyhetsarkiv-2015/Nye-nettanlegg-gir-besparelse-og-bedret-forsyningssikkerhet/

*Figure 4. Installed capacities and maximum loads 1995–2013**



* Nordel changed reporting methodology for Denmark in 2000, the sudden change from Condensing to CHP in the figure is due to the new reporting scheme.

Sources: Nordel, Nord Pool Spot and NordReg.

3.2.1 Capacity challenges in recent years

Although the overall capacity situation seems to be comfortable, measures to handle capacity challenges have been activated on some occasions in recent years. The Nordic power system is very weather dependent, due to the large share of hydro power and electrical heating. Hence, years with little inflow and cold temperatures may stress the Nordic system. The share of wind power is increasing, which increases the system's weather dependence. However, the large share of flexible hydropower can be used to mitigate the effects on the system from large wind power fluctuations. Additionally, we have seen occasional low nuclear availability in Sweden, mainly linked to upgrades of existing reactors.

According to Svenska Kraftnät (2013) the Swedish strategic reserve has been activated at three instances, and all together nine times, after 2009:

1. Winter of 2009/2010: Three times. The system was in critical condition mainly due to very low temperatures combined with low nuclear availability. The activation occurred in the day-ahead market at a price of 10–14 SEK/kWh (1,000–1,400 EUR/MWh).
2. February 2012: Five times. The activation was again mainly due to sudden low temperatures and low nuclear availability. The day-ahead market price was in the region 90–240 EUR/MWh during the activation. The reserve activation was at the highest on February 3rd 7–8 am, at 826 MW. The activation occurred in the tertiary balancing reserves market. During this period, there were available commercial bids in the tertiary reserves market that were not used. However, these were not sufficient to handle the situation completely. The difference between the available capacity in the market and the actual need was at least 400 MW. Altogether, 4,851 MWh was activated from the strategic reserve in Febrary 2012. Figure 5 shows the flows and prices in the Nordic region during this hour. The figure shows that the flows are directed towards Finland and Southern Sweden. The capacity shortage caused Elspot prices in Sweden, Finland, Northern Norway and Eastern Denmark to rise to about 200 EUR/MWh, compared to prices below 100 EUR/MWh in the surrounding areas.
3. December 2012: Once. This activation was due to unexpected cold spells and ice formation in northern Sweden, which constrained hydropower generation. The activation was 366 MW and occurred in the tertiary balancing marked at a price of around 900 EUR/MWh.

Figure 5. Flows (in MW) and prices (in EUR/MWh) February 3rd 2012 7–8 am

Source: Statnett.

The last time the Finnish reserve was activated was in the fall of 2010. The largest activation occurred October 13th in the hour 16–17, at a total of 173 MW. Denmark prepared a mothballed plant for peak loads during three months of 2008 (NordREG, 2009).

The capacity challenges in Sweden during the winter of 2009/2010 also spread to Norway. The Norwegian reservoir filling was slightly below the normal in December 2009, and the winter was cold and dry. In order to handle the situation, Statnett split Southern Norway into two and later into three bidding zones, and disconnected interruptible loads (NVE, 2010a). Additionally, a temporary dispensation for operating the reserve power plants in critical situation was given.

Sweden was divided into four bidding zones November 1, 2011. The zonal arrangement probably enables more efficient use of the grid both in Sweden and in Finland. In interviews with the TSOs, all the Nordic TSOs indicated that the bidding zone delimitation had made system operations in the Nordic market easier.

All the Nordic TSOs state that the real-time consumption in high load periods typically is lower than the volume in the day-ahead market indicates. Three possible explanations were identified in interviews with the TSOs:

1. *Prognosis error*: The load forecasting models are probably less accurate for high loads, because there exist few historical high load data points that can be used in the model calibration.
2. *Demand response*: Consumers may adapt to high Elspot prices, and thus reduce consumption when a high day-ahead price occurs.
3. *Risk aversion*: Consumers may try to avoid being in a deficit imbalance, because they are afraid of a very high deficit imbalance price. This hypothesis implies that consumers deliberately commits to a higher volume in the day-ahead market, so that the probability of facing a shortage is very small.

3.2.2 Coincidence of peak load between the Nordic countries

The loads in the Nordic countries are strongly correlated. Table 7 shows the coincidence factor in the Nordic region for 2009–2014. Here, we define the coincidence factor as the ratio of maximum load in the Nordic region to the sum of the individual maximum loads of each country. That is, a coincidence factor of one implies that peak load occurs during the same hour in all Nordic countries, and that the potential for flows between the countries is limited. A low coincidence factor implies that during peak load in one country, the loads in the neighbouring countries are lower than those country's peak loads. Hence, a smaller coincidence factor indicates less competition for peak load resources between the countries.

Table 7. Coincidence factors for the hourly loads in the Nordic region

2009	2010	2011	2012	2013	2014
0.968	0.973	0.971	0.978	0.970	0.981

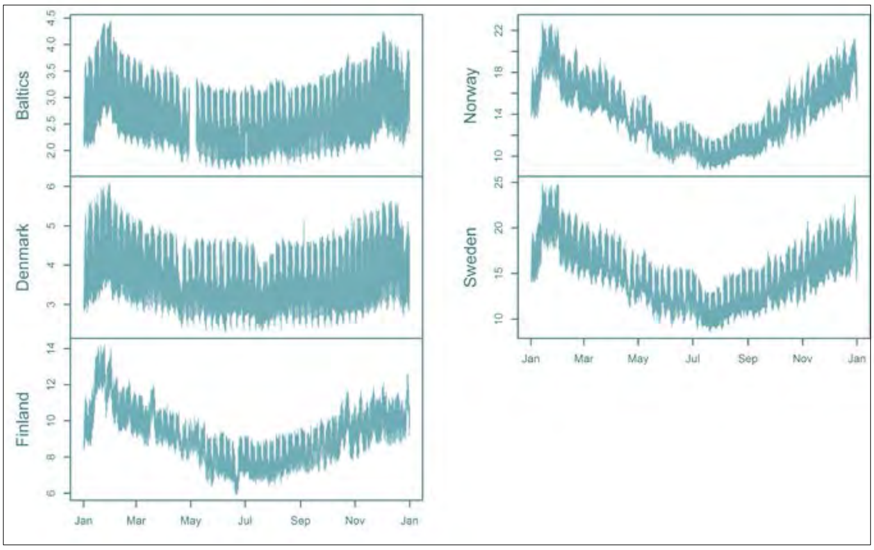
Source: NordPool Spot.

The coincidence factor for the Nordic region is generally very high. This implies that in high load periods, i.e., cold days during winter, the loads are high in all of the Nordic countries. The strongest correlation is between the loads in Norway and Sweden and between Sweden and Fin land. Denmark has a lower correlation with the other countries, although, in 2012, the load in Sweden was 98% of peak load in the Danish peak hour.

Even though there is a strong correlation between peak loads, the neighbouring countries are likely to be able to help in the event of a generation gap in an individual country. However, if outages in large plants and/or interconnector occur during a period of high load, the high coincidence factors indicate that each country cannot rely on large imports from their Nordic neighbours.

The loads in the Nordic countries are also strongly correlated with the loads in the Baltic region. Figure 6 shows that the peak load occurred at the end of January in all Nordic countries and in the Baltic region in 2014. Moreover, the loads in all countries are temperature sensitive. The difference between summer and winter loads is larger in Norway, Sweden and Finland, compared to Denmark and the Baltic region. The correlation between the Baltic load and the Danish load is therefore stronger than the correlation between the Baltic load and the other Nordic countries.

Figure 6. Hourly loads in 2014 (GW)



Source: Nord Pool Spot.

3.3 Incentives for capacity investments in the Nordic countries

It is relevant to investigate whether existing markets give adequate incentives to invest in new generation capacity. There has been significant investments in renewable energy, and a large share of the investments have been subsidised. Combined heat and power generation capacity has increased substantially over the period, because of policies favouring this technology. There have also been commercial investments in conventional power generation.

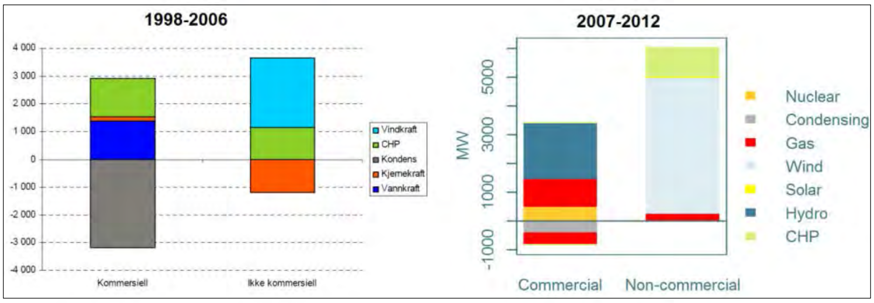
Figure 7. Net changes in generation capacity in the Nordic countries

Sources: Nordel and NordReg.

One of the motivations for the liberalisation of the Nordic electricity market was a shift towards market driven investments. Figure 7 shows the net changes in generation capacity between 1996 and 2012. Low investment rates and a phase-out of old condensing power followed the liberalisation during the 1990's. However, the investment rate has increased in recent years. Sweden and Denmark have in particular experienced considerable changes in the power system over the period, and introduced large shares of wind power.

Figure 8 shows the investments in the Nordic region between 1998 and 2012. We have extended the analysis from Econ Pöyry (2007), and split investment in commercial and non-commercial categories, based on whether investments were market driven or not.[13] The figure shows that the largest share of investments has been non-commercial.

Figure 8. Investments in Nordic generation capacity from 1998 through 2012



Sources: Econ Pöyry (2007), Nordel, Nordreg, own estimates.

The distinction between commercial and non-commercial investments is not precise. Political intervention in the market comes in many forms. The tax system may for instance be used to incentivise commercial investments in certain technologies. The Danish authorities have used tax measures to increase the share of renewables and CHP generation. A high tax on fuels used for heat generation and no tax on fuels used for electricity generation has encouraged the shift from heat-only generation to CHP. The closure of the two nuclear reactors Barsebäck 1 and 2 in 1999 and 2005, with a combined capacity of 1,200 MW, was imposed politically (Econ, 2007). (Parts of this capacity has however been re-

[13] We classify investments in hydropower as commercial. Yet, parts of the new capacity has received support through the Norwegian-Swedish Electricity Certificate Market, but we believe that the majority of the investment decisions are independent of the certificate market.

placed by expansions in the remaining nuclear reactors, resulting in about 500 MW additional capacity over the period.)

Direct subsidies is a clear-cut intervention in the market. Norwegian wind power was subsidised from 2001 through 2012, resulting in 2.1 TWh annual wind energy generation (Enova, 2014). Direct subsidies have also been used in Finland.[14] The current feed-in system includes electricity from wind, biogas, wood chips and wood plants. The basic principle is that eligible generators receive a target price, implying that the feed-in tariff varies according to a three-month average power price.[15] The eligibility period is up to 12 years. Denmark has used feed-in-tariffs to support a massive expansion of wind power capacity (Cepos, 2009). Feed-in-tariffs guarantee the generator a minimum price for the generation. The actual support level and design of Danish feed-in tariffs have been changed several times. Feed-in-tariffs have also incentivised CHP plants to switch fuels from oil and coal to natural gas and bio fuels.[16]

Sweden introduced an electricity certificate (Elcertificate) market in 2003, as a market based subsidy scheme for investments in renewable energy (NVE/Energimyndigheten, 2014). The Elcertificate market operates until 2020. In 2020, Swedish consumer's Elcertificate obligation will have supported construction of altogether 30 TWh of new renewable annual generation. Norway joined the Swedish certificate market in 2012, obliging Norwegian consumers to finance 13.2 TWh of annual renewable generation by 2020. Investments under the certificate market may take place either in Sweden or in Norway. So far, most of the new capacity has been built in Sweden.

In the last two decades, there have been commercial investments in new generation capacity. Investments in Norwegian capacity has grown after 2000, and the majority of the new capacity is small-scale hydro power (NVE, 2015), some of which have probably been invested on the promise of Elcertificates. In Finland, the majority of investments has been commercial, and in conventional technologies. There has been a reduction in Swedish and Finnish condensing power over the period, based on commercial considerations (Econ Pöyry, 2007).

Commercial investment decisions are based on expectations about future prices. The average price level in the Nordic region has been low

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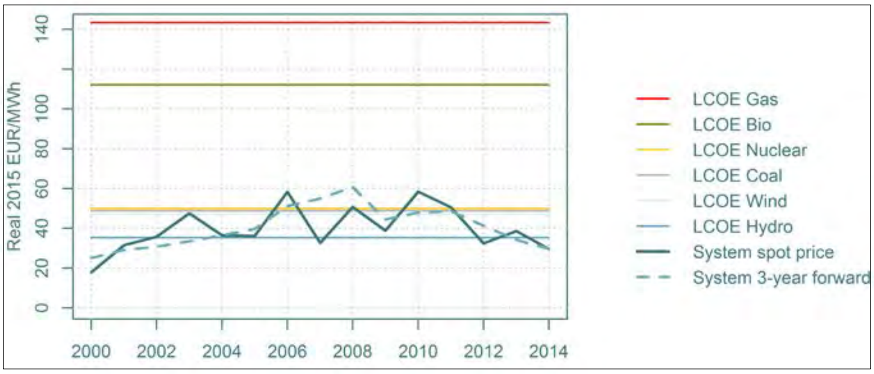
[14] http://www.erec.org/fileadmin/erec_docs/Projcet_Documents/RES2020/FINLAND_RES_Policy_Review__09_Final.pdf

[15] http://www.tem.fi/sv/energi/fornybara_energikallor/inmatningspriset_for_fornybar_energi

[16] http://www.iea.org/media/files/chp/profiles/denmark.pdf

compared to investment costs, but certain investments have been profitable based solely on day-ahead market income. Figure 9 shows the average Nordic system price since 2000, and cost estimates for the levelised cost of energy (LCOE), estimated by NVE (2015). Note that the cost estimates are for 2015, and that the costs may have changed over the period. In particular, the cost of wind power has decreased in recent years (NVE, 2015). The cost of hydropower in the figure represents the cost of the "marginal" plant that was built out in Norway. Further, the figure shows cost estimates for onshore wind power and a peak load gas turbine. A weighted average cost of capital of 4% is used, which should be considered to be a low estimate.

Figure 9. Yearly system price average and levelised cost of energy (LCOE) for 2015, estimates by NVE (2015)



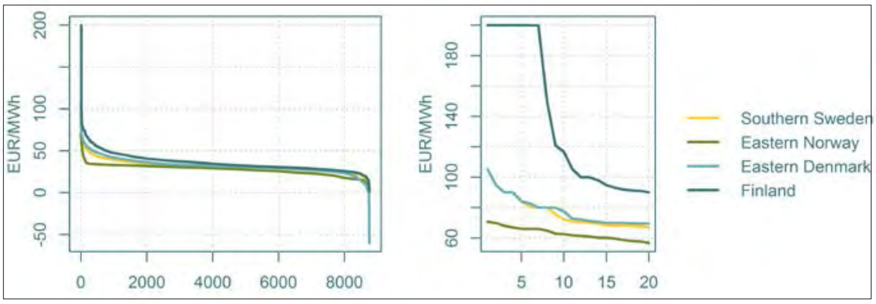
Sources: NVE (2015), NordPool Spot, and Montel.

The figure also shows the three-year forward price, which is an indication of market player's expectations about future prices. Only hydropower has a cost that is lower than the average system price. The cost of coal, nuclear and wind power is higher than the average system price. However, the forward price indicates price expectations above the LCOE for these technologies before the financial crisis in 2008. In addition, there has been significant price differences between bidding zones in recent years. Hence, the market prices may have been sufficient to motivate commercial investments over the period.

The average price is not the only relevant parameter in an investment analysis. The price structure should also be taken into account. E.g., power plants with high flexibility, such as gas turbines or reservoir hydropower, may realise a higher price than non-flexible generation, such as nuclear or wind power. Plants with high flexibility may choose to generate only when the price is high, whereas non-flexible generation produce at a stable level or when the resource (e.g. wind or sun) is available.

The price in the Nordic region is stable with occasional peaks. Figure 10 shows the price duration curves for one bidding zone per country in 2014. The large share of flexible hydropower helps stabilise the price, particularly in Norway and Northern Sweden. Moreover, the Nordic region has a large share of technologies with low or zero short-run marginal cost, such as hydropower, nuclear and wind power, which contributes to a low price level. There are very few hours with a price higher than 50 EUR/MWh. The exception is Finland, which had 769 hours with prices higher than 50 EUR/MWh. In general, the price data suggest that there is no strong incentive to invest in generation technologies with high marginal cost, to be used solely for peak demand, perhaps with the exception of Finland.

Figure 10. Price duration curves for 2014 (left), and 20 highest prices of 2014 (right)



Source: NordPool Spot.

3.4 Demand side price sensitivity

Capacity adequacy does not only depend on the generation capacity in the market. In order to assess the system’s ability to handle shortage situations and provide capacity adequacy, it is also relevant to look at the role of and experience with demand response to spot price changes. The demand side participation in other markets for flexibility is covered in previous sections.

The general development of the demand side, or more specifically how peak load will develop, is of course highly relevant in discussing future capacity adequacy. We will limit this discussion to comment on the role of energy efficiency in general.

3.4.1 Defining demand response in the context of capacity adequacy

CEER (2011) gives the following definition of demand response: Changes in electric usage by end use customers from their current consumption/injection patterns in response to:

- Changes in the price of electricity over time.
- Incentives designed to adjust electricity usage at times of high wholesale market prices or when system reliability is jeopardized.

Obviously, demand response may be important for handling capacity shortage situations. Consumers can contribute by reducing loads as a response to high prices in the spot markets (within a short or long timeframe), or by participating in different markets for flexibility, like reserve markets or capacity mechanisms. Hence, the degree of demand response depends on how price sensitive demand is, and to what extent the demand side can participate in the electricity markets.

Grid tariffs may also induce demand response. Experience with consumers' response to grid tariffs may therefore shed light on the general price sensitivity of demand.

3.4.2 Energy efficiency development

The growth in electricity and peak load demand obviously affect capacity adequacy. Energy efficiency improvements can result from various policy measures, but may also come as a response to the current or predicted electricity prices. Energy efficiency may affect energy demand, flexibility and peak load in the system.

High electricity costs over time may also increase awareness of electricity usage and result in change of behaviour to save costs. As described above, investments in new generation capacity can be done on pure commercial terms or be subject to subsidies. The same holds for energy efficiency.

Energy efficiency measures are in place in most industries in the Nordics. Numerous measures are implemented; tax deductions, white certificates, building regulations and standards, voluntary agreements and investment support (THEMA, 2013a).

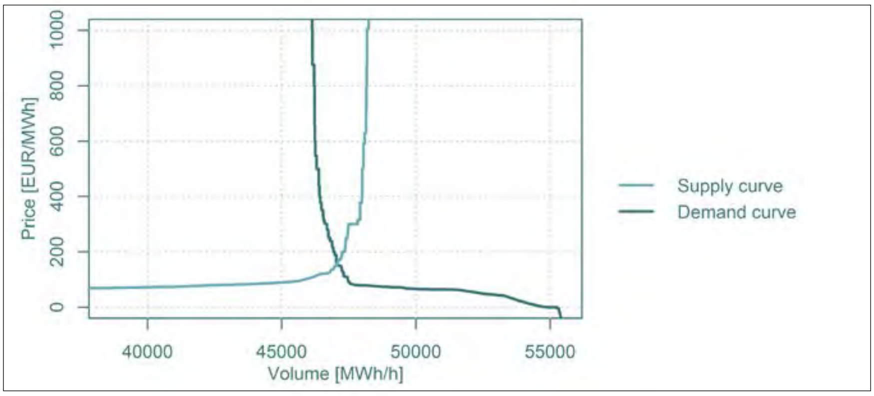
To what extent energy efficiency has reduced peak load in the Nordics is not known. We find it reasonable to believe that more efficient use of electricity also has reduced peak load.

3.4.3 Observed price sensitivity in the Elspot market

The market cross in Elspot is based on volume bids from both the demand and supply side. Demand bids may state fixed volumes, but may also be price dependent. Price dependent bids therefore reflect the demand side's price sensitivity. In discussing capacity adequacy, the price sensitivity in periods with price spikes is of special interest.

Table 8 shows the observed demand response during one hour in 2010 (December) and one hour in 2015 (January). Figure 11 shows the market cross in the 2010 hour. Both hours have high prices for that season. The majority of the demand response is available at prices below 100 EUR/MWh. During the 2010 hour, only about 1,000 MW of demand response is bid above the system price (157.59 EUR/MWh). The total flexible volume in the 2015 hour was 6,870 MW, of which about 2,300 MW where above the system price (53.57 EUR/MWh). Note that parts of the demand flexibility in the low price region (particularly at or below zero) represents pumped hydro, which buys electricity at low prices. Moreover, the majority of the observed demand response is available below prices of 100 EUR/MWh. Note that these numbers only show single hourly bids. Block bids and flexible hourly bids are not included, thus there may be additional demand response available that are not observable in our numbers.[17]

Figure 11. Market cross for the Nordic day-ahead system price at December 14 2010 between 18–19



Source: NordPool Spot.

[17] A flexible hourly bid is designed for consumers who are willing to sell back a certain volume if the price exceeds a specified level. The hour is not specified, so the demand reduction can occur during any hour. The socioeconomic welfare maximisation clearing algorithm will determine when the reduction will occur (if activated).

Table 8. Observed demand flexibility in the Nordic day-ahead market at 14 December 2010 between 18–19 and 23 January 2015 between 9–10

Price range [EUR/MWh]	14 December 2010		23 January 2015	
	MW	Per cent of total	MW	Per cent of total
-200–0	695	1.22%	1,285	2.07%
0–50	2 755	4.83%	3,222	5.19%
50–100	4,981	3.73%	482	0.78%
100–150	333	0.58%	289	0.47%
150–200	199	0.35%	233	0.38%
200–250	130	0.23%	77	0.12%
250–300	176	0.31%	173	0.28%
300–400	214	0.37%	439	0.71%
400–500	114	0.20%	242	0.39%
500–1,000	160	0.28%	229	0.37%
1,000–2,000	46	0.08%	199	0.32%
2,000 (price inflexible)	47,246	82.82%	55,166	88.93%

Source: NordPool Spot.

There are small changes in the flexibility in consumption bids in Elspot within a winter season. However, we note that the observed demand response in the winter of 2015 is smaller than that of 2010 (see Table 8). One possible explanation may be that the outlooks for the power balance for the rest of the winter differed in the two years. The Norwegian reservoir filling in the beginning of December 2010 was 57.6%, whereas the same number was 78.2% in December 2014. Our observations may indicate that more demand response is offered into Elspot if consumers expect periods with high prices (caused by low capacity margins) in the period to come. Moreover, the volume of observed demand response in Elspot does not vary significantly within a season. This may indicate that the consumers make decisions about flexible bids once or a few times each season.

We observe that the share of price insensitive bids in the day-ahead market is very large. However, all flexibility is not necessarily observable in the Elspot market. Consumers may adapt to the current price level in general, by using (price-inflexible) bids that vary dependently of the current price level. A large share of the consumers are not metered hourly, and hence have no incentive to respond to prices in the short run (day-ahead). Moreover, the value of lost load may be higher than the expected price level or the price cap in the market. Yet another reason may be that some consumers prefer to sell their flexibility in the reserve markets.

There is some evidence that some demand side flexibility exists, but is dormant, i.e. not bid, in normal situations. In 2011, THEMA conducted a study on the situation in Mid-Norway (THEMA, 2011) where we elaborated the situation awaiting a new transmission line from West-Norway. The region had a negative power balance, which resulted in higher spot prices than the system price, and occasionally, extreme spot prices. The highest observed zonal Elspot price in 2010 was 1,400 EUR/MWh. As a part of this study, we interviewed several companies within the power intensive industry in the region on how they handled this situation. The interviewees reported that the first price spikes came as a surprise, but after experiencing "unacceptable" hourly prices, they started placing price dependent bids, as they would rather shut down production for a few hours than accepting electricity prices over a certain threshold.

Some companies in the study also stated that price spikes could be exploited commercially. They could shut down production and sell their consumption in the reserve markets. One company however, had experienced a great loss when they tried this strategy. They shut down production to sell excess electricity in the market only to experience low reserve prices. Hence, they suffered a double loss – the lost production value and the loss of selling electricity at a lower price than they had paid for it.

Small consumers

A large number of consumers do not directly take part in the *price formation* through bids in the spot market. Only BRP can place bids, and small consumers are represented indirectly in the markets by their suppliers. However, also small consumers may *respond to spot prices* by reducing electricity consumption during price spikes (representing capacity shortage).

We have found no studies that implies a high level of price sensitivity from small consumers. On the contrary, several studies conclude that the observed price sensitivity in is low, and that the price sensitivity may have decreased during the last years.

Risø (2006) states that the observed price sensitivity in the Danish market is very low. Price increases of one % causes a demand reduction of only 0.005 to 0.1%.

In 2011, Statistics Norway analysed how the general consumption of electricity (except power intensive industry) reacted to changes in the Elspot price (SSB, 2011). An econometric error correction model was used on monthly data for the period 1996–2010. The study found that if the spot price increases by 1% from one month to another, electricity consumption falls by 0.05%. Most of the change in consumption takes place in the same month as the price change. The study found that the price sensitivity of electricity consumption seems to have decreased from 1996 to 2010. This may be explained both by reduced flexibility at the consumption site (fewer households has wood stove and fewer interruptible electric boilers as a result of phase-out of oil burners), and by reduced cost of energy due to increased energy efficiency (partly due to an increasing number of heat pumps).

There are many possible reasons for the low price sensitivity from small consumers. With the exception of Finnish households, few Nordic households are metered hourly. Short-term price spikes will not provide incentives for short time demand response for consumers without hourly metering. Large buildings are generally metered hourly in all the Nordic countries; the lack of hourly metering in households does therefore not explain the lack of price sensitivity in general.

Limited price variations may partly explain the low price sensitivity. Substantial price spikes are not common in the Nordic market. There are price variations during the day and between seasons and years, but these variations are generally not sufficient to provide significant returns to unleash demand response.

A large share of small consumers, at least in Finland and Denmark, still have fixed price contracts. Fixed price contracts do not yield incentives for hourly demand response, as they shelter end-users from variations in hourly spot prices. End-users on fixed contracts may however be incentivized to respond to price signals through other (additional) mechanisms. For example, Finnish consumers often have a time-of-use supply tariff with fixed prices differentiated between day and night. Most single homes also has installed heat storage (water tanks) that are heated during the night and used to heat the house during the day. Gaia (2011) estimates that 1,000 MW power is moved from day to night due to this arrangement.

3.5 Summary of findings

The ability of the market to handle shortages and capacity challenges depends on the market design and the underlying market fundamentals. The Nord Pool market area is a mature market with a market design providing opportunities for market balancing in the long-term, via financial markets, in the short term via Elsport and Elbas, and in real-time via different measures at the disposal of the TSOs. Markets in different time frames and Design of markets in different time frames and the TSOs.

The Nordic market area has experienced few capacity shortages in recent years. There have been market based investments in conventional generation capacity, although most of the new capacity is based on support schemes for renewable energy. The generation set-up has provided sufficient flexibility and energy back-up to handle the fluctuations in weather seen in recent years. There have been capacity incidents in Sweden during a cold and dry winter with low nuclear availability. However, the current strategic reserves have been more than sufficient to cover the capacity gap. Finland activated its strategic reserve the last time in 2010. We find that there is a bias towards too high consumption in the day-ahead market in high load periods, which may increase the probability of a generation gap in the spot markets.

The demand side is to some extent active in relevant market places. The demand side takes part, and increasingly so, in reserve markets and capacity mechanisms. Large consumers provide demand response in these markets. Required volumes and response times etc. is however a barrier for most consumers. Price sensitive bids from the demand side are observed in Elspot during periods of high prices. The role of small consumers in handling capacity shortage is currently low, as they do not participate in the market place directly. Small consumers are also not faced with short time price signals in the spot price, and therefore it should be no surprise that they do not respond to short time price spikes.

4. Generation gap Outlook

In Chapter 3, we assessed and described aspects relevant for the current adequacy situation in the Nordic market. In this chapter, we discuss the prospects for the future. We look at adequacy studies by different sources, and what factors and drivers are deemed to affect the future capacity adequacy. First, we give an overview of generation gap assessments from external sources. Then we discuss forecast for the need for flexibility, and estimates of potentials and costs for future demand response. Finally, we present a simplified model assessment of the outlook for generation gaps in 2030. However, we do not provide a full capacity assessment.

4.1 Existing analyses

There are few studies of future capacity adequacy in the Nordic region. Most of the existing studies focus on developments in annual (energy) generation and consumption, rather than on availability of reliable available capacity and the developments in (peak) loads.

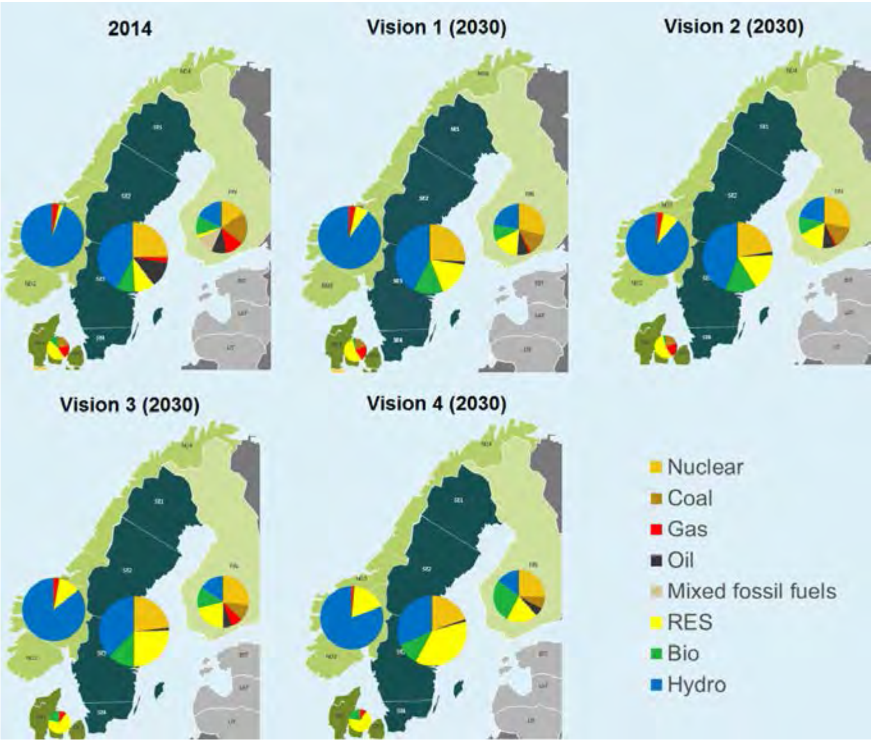
4.1.1 ENTSO-E SO&AF

The most relevant study related to capacity adequacy is the Scenario outlook and adequacy forecast (SO&AF) of ENTSO-E (2014). This study investigates the peak load margin, but does not analyse flexibility and energy back-up. The study contains four "visions" for 2030. The visions are constructed in order to describe the range of possible outcomes in 2030, with varying degrees of market integration and progress towards the European energy targets for 2050. In particular, "Vision 4" gives the state of the system under a "green revolution", meaning a high degree of integration of the European electricity markets and a development that is compatible with the objectives in the EU roadmap for 2050.[18]

[18] http://www.roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf

Figure 12 shows the share of generation capacities in 2014 and in the four visions made for 2030 for the Nordic market. The figure shows that the energy system may change significantly to 2030. In all visions, the share of wind and solar power (RES) increases substantially from current levels. The change is most substantial in Vision 4 ("green revolution"). Moreover, the installed thermal capacity is decreasing in all visions. In all visions, the peak loads increase slightly towards 2030. Demand response is not accounted for as a measure to reduce peak loads in ENTSO-E's visions.

Figure 12. Generation capacities in 2014 and ENTSO-E visions for 2030



Source: ENTSO-E (2014).

Denmark

The ENTSO-E visions depict a steady phase out of fossil fuels in Denmark. Coal capacity accounts for most of the reduction, namely from 2,410 MW in 2014 to 550 MW in 2025. The visions indicate a small increase in natural gas capacity, resulting in a capacity between 2,010 and 3,170 MW in 2030. The installed capacity in Denmark increases to 2030, mainly due to new wind and bio capacity. The installed wind capacity is in the region of 6,850 to 11,460 MW by 2030, depending on the vision. Due to the high share of intermittent wind power, the reliable available capacity is less than peak load in all visions. Denmark is therefore likely to depend more on imports during peak loads, compared to the current situation.

Finland

Finland currently depends on imports during peak load. However, the visions indicate Finnish nuclear capacity to increase from 4,890 in 2014 to 6,490 in 2030, resulting in a reliable available capacity larger than peak load. Thus, Finland does not depend on imports during peak load in ENTOS-E's visions for 2030. Installed wind capacity increases, yet, the share of wind remains moderate in all visions. In the most ambitious vision, biomass increases to 7,050 MW and fossil fuels decreases to 5,360 MW by 2030.

Norway

The visions show a strong capacity balance in Norway going forward. Even in Vision 4 ("green revolution"), Norway has a peak capacity margin against peak load of 2 GW due to the large share of flexible hydropower. Thus, there are small changes in the capacity margin in Norway in the four visions.

Sweden

According to the ENTSO-E visions, the uncertainty in the capacity development in Sweden is large. In particular, the wind capacity in 2030 varies in the range 6,250 to 19,000 MW. There are no substantial changes in installed nuclear capacity in any of the visions. That is, none of the current nuclear reactors are phased out in visions 1, 3 and 4, whereas two reactors (corresponding to Ringhals 1 and Ringhals 2) are phased out in Vision 2. The majority of fossil fuel capacity is phased out, and bio capacity increases to 5,300 MW by 2030. Moreover, the visions show no changes in installed hydro capacity. The reliable available capacity is greater than peak load in all visions, except in the case of a delay in the EU energy roadmap to 2050, combined with a high degree of European market integration. In the latter case, Sweden depends on imports during peak load.

The Nordic region as a whole

The ENTSO-E visions do not depict any capacity shortages in 2030 in the Nordic Region. Denmark depends increasingly on imports in order to cover peak demand. However, an increased capacity surplus in Norway and Finland, in combination with more interconnectors, more than offsets the capacity deficit in Denmark.

The Baltic region

All ENTSO-E visions depicts reliable available capacity higher than the peak load in the Baltic region. The visions include an increase in nuclear capacity of 1.3 MW, a decrease in the coal generation capacity from 700 to 1,300 MW until 2030, and an increase in bio generation from 500 to 700 MW. Wind power capacity increases significantly in all visions, and particularly in Visions 3 and 4, where the gas capacity increases as well. Peak load increases moderately, resulting in a positive peak load margin in all the Baltic countries.

4.1.2 The Swedish Energy Agency (2013)

The Swedish Energy Agency (2013) studies the power balance in the Nordic region in 2030. The study finds that the power balance in the Nordic region is satisfactory. A small increase in the Swedish nuclear capacity up to 2020, due to continued upgrades in existing reactors, followed by a phase out of three reactors in the 2020's, result in a nuclear capacity of 7,900 MW in 2030. The study does however point out that there will be a power deficit if old nuclear and condensing capacity in Sweden and Finland is phased out and is replaced solely by generation with low reliability.

The assumptions for installed capacities, de-rated capacities and peak loads in a high load scenario for 2030 are shown in Figure 13.

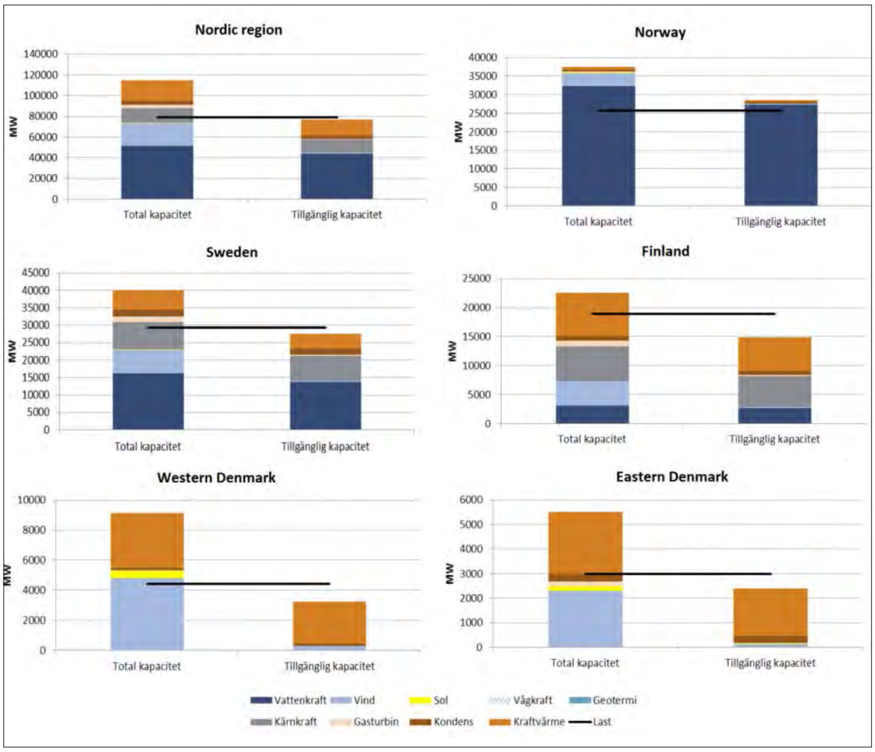
The combined reliable available capacity in the Nordic region is almost sufficient to cover the peak load. Norway has net exports during peak load, whereas the other countries rely on imports during peak load. The study uses availability factors to de-rate the installed capacities, shown in Table 9.

Table 9. Availability (de-rating) factors used by the Swedish Energy Agency (2013)

	Hydro power	Nuclear	Wind power	Gas turbines	Condensing power	Back-pressure
Availability factor	85%	89%	6%	21%	90%	77%

Source: The Swedish Energy Agency (2013).

Figure 13. Installed capacity, reliable available capacities and peak loads in the high load scenario in 2030 of The Swedish Energy Agency (2013)



Source: The Swedish Energy Agency (2013).

4.1.3 Other studies

A recent Finnish study concludes that Finland will have a negative peak load margin in 2030 of about 1,300 MW in a normal year and 2,500 MW in a cold year in the best estimate scenario (Pöyry, 2015). The capacity deficit is larger both in the high economic growth scenario (3,500 MW in a cold winter) and the low economic growth scenario (3,000 MW in a cold winter). A stronger Finnish capacity balance following the commissioning of Olkilouto 3 in 2018 is expected. However, the peak load is assumed to be higher than in ENTSO-E's visions, and the nuclear capacity lower, resulting in a negative peak load margin. Yet, there will be a power shortage only in the event of fault situations in several generation units and/or limited transmission connections, according to the study. An import capacity of almost 6,000 MW into Finland in 2030, including 1,400 MW from Russia, is assumed.

SvK has conducted an internal study of the power balance in 2025 if three of the current nuclear plants are phased out (Ringhals 1 and 2, and Oskarshamn 1). The study foresees a reliable available capacity of

24,860 MW, and a power consumption of 26,500 MW in a normal winter and 28,000 MW in a cold winter. The nuclear phase-out will cause larger deficits in Southern Sweden, estimated to 7,060 MW in SE3 and 3,280 MW in SE4 in a cold winter in 2025.

The Swedish Energy Markets Inspectorate has also performed an internal analysis of the power and energy balance in 2025. In this study, the peak load in a cold winter is assumed to be 29,000 MW in 2025. This study also finds that the two southernmost regions of Sweden will depend on imports during peak load. Yet, the study concludes that the import capacity into these regions is sufficient to cover the required imports.

Energinet.dk (2014) assumes a steady growth in peak demand in Denmark, resulting in a peak load of 6,864 MW in a normal winter and 7,372 MW in a cold ("10-year") winter in 2030.

The Baltic power system is expected to change significantly over the next years. The share of renewable energy, in particular wind power, is expected to increase (Elforsk, 2012a). A new nuclear power plant in Lithuania of 1,350 MW is planned, and is expected to go online in 2022.[19] There may also be investments in new thermal generation, Elforsk (2012a) predicts both new CHP plants and condensing plants in the Baltic region, and a gradual phase-out of old Lithuanian power plants. Moreover, the Baltic electricity market is becoming more integrated with the Nordic region and Continental Europe due to new transmission capacity to Sweden and Poland.

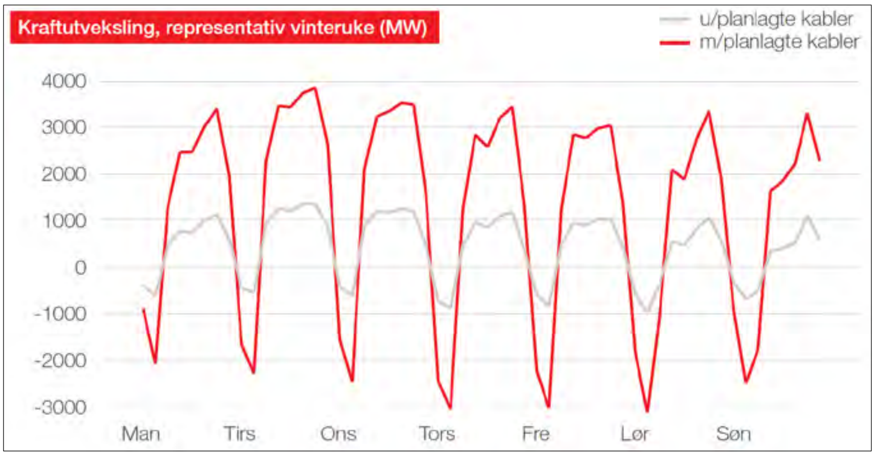
4.2 Need for flexibility

None of the studies on future capacity adequacy that we have found, focus on the demand for flexible resources, nor on the need for energy back-up. At the same time, all scenarios depict an increase in renewable generation capacity, in particular wind power generation, and an increase in the interconnector capacities. These are factors that may imply an increased need for reserves in the system.

Simulations made by Statnett show that the load variations in Norway increase when new interconnectors to UK and Germany increase the exchange capacity (Figure 14). Similarly, larger shares of variable renewable generation may create larger flow variations in the system.

[19] http://www.vae.lt/en/

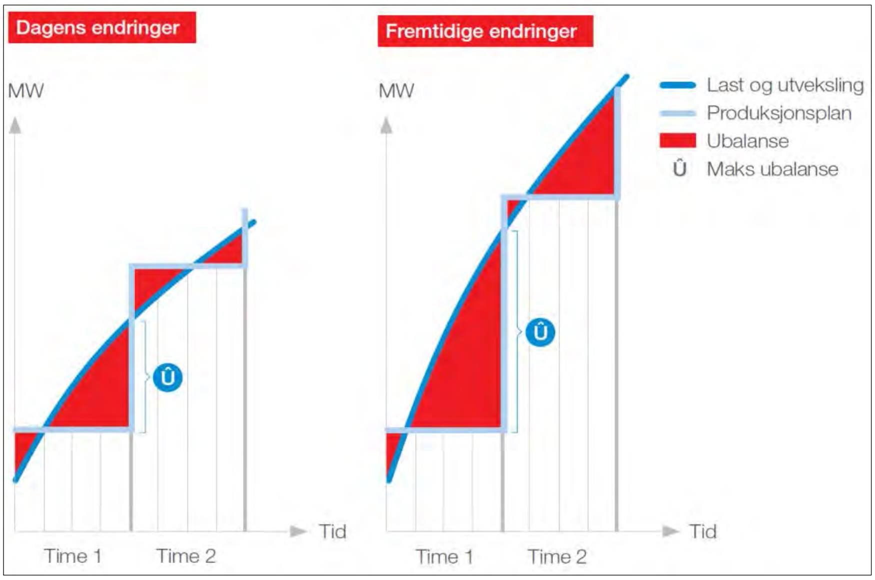
Figure 14. Hourly import and export to/from Norway in a representative winter week (MW)



Source: Statnett.

The larger fluctuations in flows from near full imports during the night and near full exports during the day, due to increased interconnector capacity, creates larger structural imbalances, as Figure 15 shows. With hourly time resolution in the day-ahead market, the increase in structural imbalances implies that the TSO must acquire more balancing reserves.

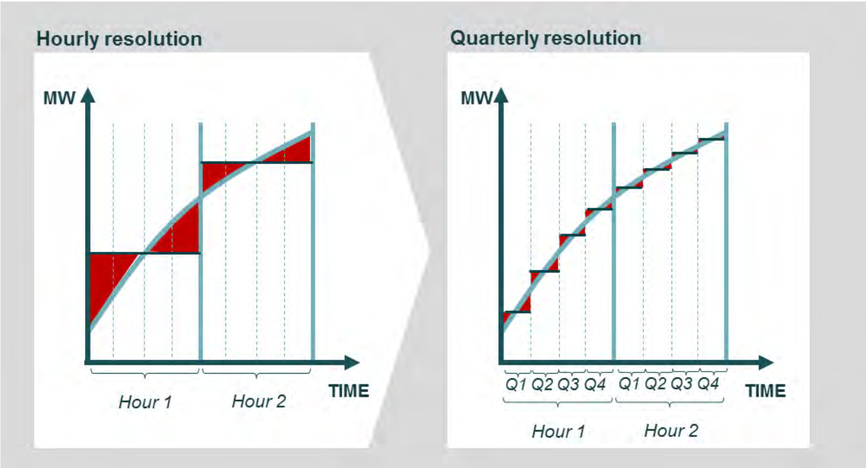
Figure 15. Structural imbalances within hours with current and future exchange capacity



Source: Statnett.

The need for balancing resources to manage structural imbalances is related to the market design. If the time resolution in Elspot was changed from hourly to 15-minute resolution, the need for balancing reserves would be much smaller, as illustrated in Figure 16..

Figure 16. Structural imbalances with hourly and 15-minute resolution in the day-ahead market



Source: Statnett.

The Norwegian TSO expects the cost of reserves to increase as a result of new interconnectors, more intermittent generation, and goals about increased frequency quality (Statnett, 2014). In particular, Statnett expects the cost of automatic (primary and secondary) reserves to increase. This will increase the revenue of providers of reserves, but the estimates are uncertain.

Also the Swedish TSO points at challenges as a result of new interconnectors, and that this may be solved by increasing the volume of automatic reserves.[20]

[20] Information obtained via email exchange.

4.3 Demand flexibility – potentials and costs

The general development of the electricity demand affect future capacity adequacy. The increase in peak load is expected to be moderate in the Nordic market, but large changes in demand from industry, heating or large-scale electrification of transport may increase demand in peak load. On the other hand, all segments may provide flexibility reserves. If demand response is utilized, new loads do not necessarily increase future peak load in the Nordic system.

Moreover, the demand side is likely to play a more active role in the future energy system. Technology development, and market and regulatory developments, may cater for increasing demand participation in the market. To what extent the demand side will provide increased flexibility to the power system in the future, depends on price developments as well as changes in regulations, market design and other incentives. We will therefore discuss drivers and barriers that influence future demand response.

In order for the demand side to reduce their consumption during (short) periods of capacity shortage:

- The underlying consumption must be flexible and the flexibility must be relevant for the specific shortage situation.
- The consumption must be price-sensitive.
- The price signal must be available and understood by the consumer.
- The compensation for the response must be greater than the cost.

To estimate the scope of demand response in the market is however complex, and estimates are deemed to be uncertain. The main reasons for the uncertainty is the historically relatively low price levels and, in particular, little hourly price variation in the Nordic market, and different technological and other barriers to demand participation. Hence, historical data provides a poor basis for assessment of future demand response.

The demand side is far more diverse than the supply side in terms of size, technology, price sensitivity, regulation, etc. Therefore, we will discuss the future potential for demand response in industry, large buildings and households separately. Our discussion of potentials is based on prior assessments that provide some examples of costs in different segments and markets. These data are supplied with a qualitative discussion of drivers and barriers to unleash increased demand response in capacity shortage.

4.3.1 Demand response potentials

There are no studies quantifying the total potential for demand response in the Nordic region. Gaia (2011) did however summarise a "practical potential for demand flexibility in the Nordic area on the medium term" of about 12,000 MW, based on information from the TSOs action plans (see Table 4.2). Gaia describes the results in the table as conservative, and notes that the cost of utilising the potential must be compared to the benefits of doing so. Gaia also states in the report that the demand response from industry probably will be more accessible than demand response from households.

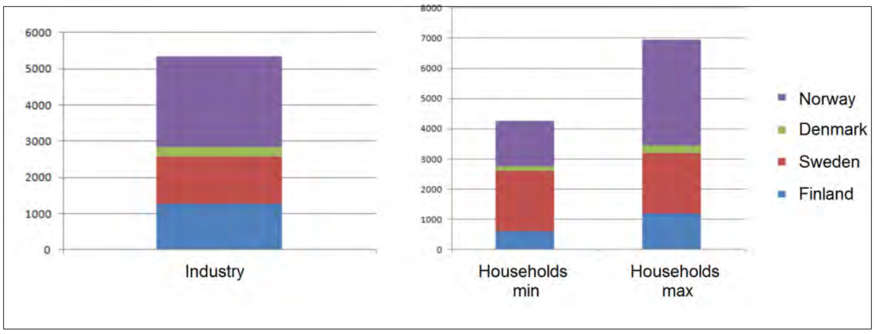
Table 10. . Estimated total potential for demand response in the Nordic area on the medium term

	Norway	Sweden	Finland	Denmark
Demand response potential	5,000 MW	4,000 MW	2,500 MW	500 MW

Source: Gaia (2011).

Gaia (2011) also states that there are few reliable and current studies of the potential for demand response. It is also uncertain to what extent the potential is already represented in the market today. Based on existing studies for the Nordic market, Gaia estimates a potential of 10–12,000 MW of flexible demand. The study finds that electrically heated homes and the energy intensive industry represent the largest potential for demand response. The potential for demand response also varies between the countries, reflecting the share of electricity consumed in large industry and the share of homes heated with electricity.

Figure 17. Distribution of the potential for demand response in the Nordic countries. Industry (top) and households (bottom)



Source: Gaia (2011).

4.3.2 Industry

As stated, there is a potentially large potential for demand response for the industry. On the other hand, large industry is already active in reserve markets and is to some extent providing price sensitive bids in the spot market. The remaining questions are therefore if there is additional volumes that may be activated in the case of capacity shortage – and what it takes to provide such response.

Both increased price sensitivity in spot markets and participation in reserve markets may be relevant for industrial consumers.

Estimates of potentials and costs

The literature does not provide estimates of the costs of unleashing demand response from the Nordic industry as a whole. Relevant costs would include investments in energy control systems, but also focus and time for management and operational staff, and last but not least, the risk for lost production or damage on industrial equipment. However, we will present some different cost estimates for different countries:

Dansk Energi Analyse (2010) conducted a project during 2006–2010, which aimed to increase the Danish industry's interest to engage in the different electricity markets. The study showed that price levels in the spot market and the reserve market during this period made these markets unattractive for the industry players. If the payment in the reserve market were less than DKK 200,000 (EUR 27,000) per MW per year, the companies in the project would not find it interesting to participate in the market. If the level increased to DKK 400,000–600,000 (EUR 54,000–80,000) per MW per year, the interest would however be significant. The price level per activation will thus be lower the more frequently the volumes are activated.

Fingrid (2014) predict the demand side participation in reserve markets to increase by 500–1,000 MW by 2020, most of which is expected to come from existing large industry. However, volumes from smaller players that are not very active today are also expected to increase. According to Gaia (2011), there is a flexibility potential of 500 MW in Finnish industry, but the potential is rather uncertain as it is not clear if this is an additional potential to the flexibility currently utilized in the market.

The latest study of the potential for demand flexibility in Norway is from 2006 (NVE, 2006). This study shows a 2–3 TWh potential for short-term flexibility from the Norwegian industry. The flexibility potential in this study is given in terms of energy and not capacity, and is based on the loads with interruptible contracts with the DSOs at that time. (This potential is included in the volume reported in Gaia, 2011). The study does not discuss costs.

According to Elforsk (2006), in a study of 30 different Swedish industrial consumers, find that they may each reduce their consumption by 5 to 50 MW for a few hours during price peaks. The study reported a rather linear volume reduction in the price interval from 500 to 10,000 SEK/MWh (54–1072 EUR/MWh). To unleash the full potential of 1,600 MW for all the 30 power intensive industries included in the study, the price peak needed to reach 13,000 SEK/MWh (1,393 EUR/MWh). According to Gaia (2011), EME Analys estimated the potential for demand side flexibility in the Swedish industry as a whole to approximately 1,300 MW. To unleash the total potential, price peaks of 90,000 SEK/MWh (9,646 EUR/MWh) is needed for about 10 hour a year. Alas, the two studies differ both in terms of volume and price levels.

An example from another Swedish study (Sweco, 2013), estimates the cost of implementing power control in the Swedish food industry to SEK 500,000 (EUR 53,600), of which equipment costs amount to SEK 150–200,000 (EUR 16,080–21,435). The technical cost of power control is not very high compared to prices in the reserve markets, but may still be considered as an investment risk if the income potential is not easy to predict.

Drivers for increased demand response from industry

Price variations in the Nordic electricity system are relatively small and may constitute a barrier for demand response. The volatility of spot prices may however increase. If the volatility in spot prices makes it interesting for industry to focus on demand response on a daily basis, the general awareness of possibilities in the electricity market will probably increase. Increased profitability and awareness may also increase the utilization of demand response, by increased price dependent bids or increased activity in Elbas.

The number of energy service providers in the industry segment may increase. For example, Enfo has announced that they will offer aggregator services for industries in Norway and Sweden,[21] to provide market access for the demand side. This implies that Enfo considers services to provide more demand response in existing markets as commercial attractive, and indicates that there may be a potential for increased future demand side flexibility in the Nordic market.

Barriers for increased demand response from industry

For industry in general, the production process of the industry plant is the main concern for managers and daily operation, not energy issues. When the invested time and focus is included, the costs of demand response may be too high. In addition, interfering with the production process by shutting down machinery for some time may increase the risk of failure or unwanted side effects of interfering with the normal procedure. The larger the share of energy cost in the total costs, the more important energy issues will be. As observed, power intensive industry is also represented in power markets today.

Even if price volatility in the electricity markets increase, the general price level may be low, and too low to create awareness from the industry. Planning schedules in industrial processes are normally rather long, and too long to respond in short term price variations without high cost of personnel etc. Such costs may lead to high costs also for demand response. Hence, the cost of activating demand response may be high for large parts of the industry, and the total cost is difficult to estimate. The "true" cost of demand response will only be revealed through actual market response to price changes in the future.

To participate in reserve markets, the minimum volume is 10 MW (tertiary reserves). The required minimum volume is therefore a substantial barrier for most industries and the demand side in general.

[21] Enfo is a Norwegian company developing and operating advanced technology to promote demand response and smart grid.

4.3.3 *Large buildings*

As stated in section 3.4, the price sensitivity of electricity outside of industry is considered low. In all Nordic countries, the electricity consumption in large buildings is metered on an hourly basis (THEMA, 2015b). Hence, spot price variations are reflected in the electricity bill for large buildings, and the consumer *may respond* to high spot prices during capacity shortage to save costs. They do not participate in the electricity markets directly and can only participate indirectly through the supplier (i.e. through price sensitive bids based on the observed price sensitivity from buildings) or possibly other service providers (i.e. bids in reserve markets through aggregators) holding balancing responsibility.

Potentials and costs

According to EA Energianalyse (2011), 50% of the electricity used for cooling and freezing processes in Danish production companies might be flexible, while as much as 70% of the electricity used for the same purposes in the trade and service sector might be flexible (supermarkets). Supermarkets are closed during nights and may use these hours for extra cooling, thereby reducing their demand for cooling during peak hours in the morning. Ventilation is the second largest contributor of demand flexibility for large electricity consumers. The study estimates that 15% of the electricity used for ventilation in the trade and service sector might be flexible. Electricity used for ventilation in industrial companies is expected to have a larger potential for flexibility due to a less sensitive comfort level in this sector.

Demand flexibility in Sweden is summarized in Sweco (2013). The potential for load reduction with a duration of three hours from large buildings is estimated to 200 MW. Most of the potential comes from ventilation and cooling in office buildings. This potential is supposed to be easily available through re-programming of existing automation systems and could be realized at spot prices above 3 SEK/kWh (0.3 EUR/kWh).

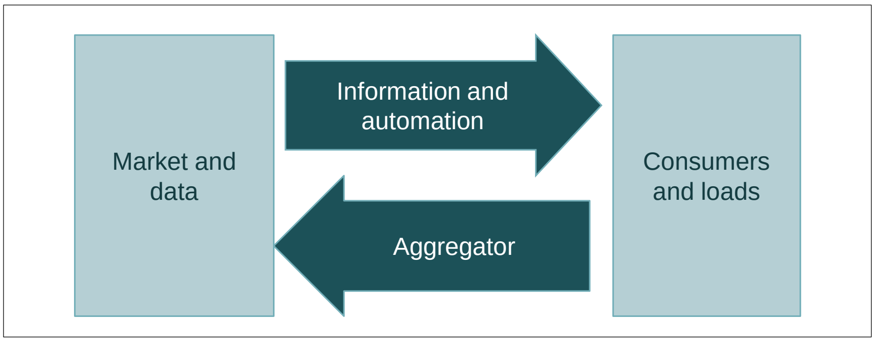
Drivers for increased demand response from large buildings

As stated before, large building do not provide demand response in the current situation. This fact in itself may be seen as an opportunity for this sector to increase response on price signals – if prices or price signals increase or if demand response is made easier.

Large buildings often have central operating systems and may control separate loads automatically and/or remotely. Building automation or an energy service provider might increase the price sensitivity. In Norway, there are several companies offering energy services to this segment to optimise energy usage and costs, and there are technology providers in place in all countries. Services offered by such companies may increase in all Nordic countries and help increase the price sensitivity of electricity consumption in large buildings.

The cost of time and focus required by the consumer in order to provide flexibility is often underestimated in assessments of the potential for energy efficiency and demand response. Such costs may represent important barriers for the enabling of the demand flexibility potential, and even for the potential that may be economically viable. Energy service providers may help bring down such costs and reduce the barriers and make demand response more manageable to consumers, either by notifying when high prices occur or by enabling automated responses based on predefined price limits. In this sense, service providers help *bringing the market to the loads*, see figure 4.7. Aggregators may also be interested in including loads in large buildings in aggregated volumes offered in reserve markets in the future and thereby help *bringing loads to the market*. In the current market design, BRP is a prerequisite for aggregators or others to participate in both reserve markets and the spot market.

Figure 18. Service providers enabling demand response



Barriers for increased demand response from large buildings
Current price variations in the spot price is low, the profitability of responding to price variations is therefore low. Many consumers, included large buildings, have supplier contracts based on fixed electricity prices. Such contracts may be seen as an indication that the consumer does not want to provide flexibility. On the other hand, contracts that pay for demand response may be combined with fix price contracts. Hence, fixed price contracts are not a barrier for demand response in general.

Historically, oil boilers have been a common source of heating in large buildings. As a means to reduce CO_2 emissions, oil burners will to a large extend be phased out. The phase out of oil burners will possibly influence demand response in two ways; by increasing peak load and by reducing the ability for demand response from buildings. There are three main alternatives to oil burners for heating; electric heating, heat pumps or other energy sources than electricity (district heating or bio energy). The two first options will increase peak load and thereby influence capacity adequacy. The flexibility of electricity demand may also be reduced, since many buildings often have a combination of oil and electrical burners. Electricity demand in such setup had a high degree of flexibility, since there was a full back-up from the oil burners and electricity price spikes would always result in low electricity consumption.

The lack of knowledge and focus on energy issues may act as a barrier when it comes to taking part in demand response schemes. As described above, service providers may reduce this barrier.

4.3.4 Households

In the same way as larger buildings, households may respond to high price spikes even if they are not active in the electricity markets. Electricity use in households represents a possible source of demand response in the future. The roll-out of smart meters in the Nordics may enable increased demand response, but is not itself sufficient to realize the potential.

Potentials and cost from literature

Demand response is most relevant for households with electrical heating. The share of electrically heated homes varies substantially between the countries. According to Gaia (2011), electrically heated homes in the Nordic countries, each has a potential of switching 1–2 kW from peak hours to off-peak hours. The total estimate of 4000–7000 MW flexible demand from households is based on the share of electrically heated homes and the estimated volumes per house. Approximately 6% of Danish, 80% of Norwegian and 50% of Swedish households are currently electrically heated (Gaia, 2011). In Finland, where also a large share of households are electrically heated, the flexibility is to some extent already utilized (i.e moved from day to night). As we understand the potentials presented by Gaia, the potential demand response for Finnish households presented in Figure 17 is not relevant to reduce peak load further since this volume is not in use during peak load – the flexibility is already utilized.

The Gaia study, and other studies examined, does not describe the cost side for demand response from households.

According to Sweco (2013), single homes account for 70% of all electricity used for heating (included heating of tap water) in Sweden. Electrically heated houses represent a potential to reduce 4–5 kW each in the period 8–10 in the morning (representing the peak load for the household, the potential will be lower outside of this hours), even with outdoor temperatures at 10–15 degrees below, without loss of comfort. The total potential for demand reductions for these households is estimated to 1500 MW (Sweco, 2013). The households' savings are estimated based on historical price variations in 2010 and 2011. The actual cost of realizing this demand response is not estimated. However, a Swedish study shows that consumers are willing to reduce loads if they are informed of hours with high electricity prices. When consumers were informed by SMS or email, household consumption was reduced by 50% in high price hours (Sweco, 2013).

Broberg *et al.* (2014) discuss the households' willingness to participate in different demand response schemes where some loads may be remotely controlled. The study estimates what level of compensation is needed for remote control of heating or general electric equipment at different times of day, and more generally in extreme situation. The study finds that the compensation needed to accept external control is lower for heating than for other appliances. Table 4.3 provides a summayr of the results.

Table 11. Average necessary compensation for Swedish households to take part in demand response schemes

The suggested scheme for remote control of electricity consumption	Yearly compensation compared to no remote control
Compared to no remote control of heating:	
Demanded compensation for remote control in the morning (7.00–10.00)	No significant compensation
Demanded compensation for remote control in the afternoon (17.00–20.00)	SEK 630
Compared to no control of electricity consumption in general:	SEK 829
Demanded compensation for remote control in the morning (7.00–10.00)	
Demanded compensation for remote control in the afternoon (17.00–20.00)	SEK 1,435
Compared to no remote control in extreme situations	SEK 44 per day
Demanded compensation for remote control in extreme situations	
Demanded compensation to change todays contract.	SEK 2,746

Source: Broberg *et al.* (2014).

Broberg *et al.* (2014) notes that the results cannot be translated into a cost per kW demand response, as it is not the cost for a specific load reduction (EUR/MW), but the compensation needed for the household to be willing to participate in the scheme for load control. We do not know if loads are turned on when load reductions are needed or how often the loads may be disconnected. The study also indicates that consumers are more willing to take part in demand response schemes at times when they are not at home, i.e., when they are not directly affected by the (potential) load reductions.

Drivers for increased demand response from households

Unlike large consumers (industry and large buildings), households have not had any incentives to take an active role in the electricity system. This may change. Hourly metering makes it possible for the consumer to respond to hourly variations in the spot price. Smart meters with hourly metering are already in place in Finland and will be installed in Norway and Denmark before 2020. In these three countries, the DSOs will collect and report consumption data on a daily basis. Swedish households have had smart meters with monthly metering since 2009. However, if requested by the consumer, the Swedish DSOs must install hourly metering without extra cost.

The roll-out of smart meters may increase price sensitivity for electricity consumption in households. Smart meters is a prerequisite for demand response from households, but enabling consumers to respond to price signals also requires information on price spikes or some sort of "smart home" solutions. In order for consumers to invest in home automation, it must be beneficial for the consumer in some way; reduced electricity bill, increased comfort, or the feeling of "doing good".

In the future, electrical appliances may be equipped with "Internet of things" functionalities that make them prepared for remote control by home automation or from tablets, phones or PCs. Such functionality embedded in appliances will lower the cost of home automation functionalities, and thereby lower the cost of demand response from small loads. However, such appliances are not widely used as of today, and the potential for future peak load flexibility is not clear.

Barriers for increased demand response from households

There are several barriers for households to offer demand response. The common use of fixed price electricity contracts in the Nordic countries (except in Norway and partly in Sweden) shield the consumers from market price signals, and may mute the demand response, unless incentives for flexibility is given in some other way by the supplier or by service providers. Fixed price contracts may still serve as a barrier to demand response if the consumers' value cost avoidance (response to high variable prices) higher than increased revenues (response to flexibility payments). This is an empirical question.

As for other sectors, low volatility in the spot prices imply low returns to demand response in terms of load shifting. For small loads, the cost side is even more challenging. Relevant costs for households are both the home automation systems needed, but also the (risk of) reduced comfort or extra time spent when responding to price signals or taking part in demand response schemes.

General consumer issues may also serve as a barrier for households to provide demand response as they are the least professional consumer group (even if such issues may be highly relevant also for professional consumers). The results from Broberg *et al.* (2014), shown in Table 11, identifies a separate estimate for the compensation needed in order to change from today's contract. The high cost estimate could partly reflect weaknesses in the methodology used, but in general, welfare economic studies support a strong bias in favour of status quo situations. Other consumer biases may also affect how consumers relate to the electricity market, as the energy market is complex and may be confusing to the end-users. According to Ofgem (2011) and Waddam & Wilson (2007), the ability of small consumers to take rational decisions in the electricity market is limited. For some users it is difficult to understand how the choice of contracts for electricity supply will affect their cost of electricity. There may also be different types of psychological barriers to change contracts of electricity and such barriers are strengthened by the complexity of the electricity market (THEMA, 2013). The studies of consumers' biases in the electricity market is focussed on selecting supplier contracts. Demand response schemes could easily be more complex than a supplier contract, we therefore see the biases as relevant also for demand response.

4.3.5 Summary of findings

Demand already plays a role in handling capacity shortages as described in chapter 3. Due to the diversity of the demand side, we cannot predict the potential for demand response other than the volumes observed in the market. However, most studies identify some demand response, although the potentials and costs are very uncertain. It is difficult to make predictions for the future based on historical data, because both the price dynamics and new technology, in combination with changes in the market design, may cater for not yet observed demand response. If stronger price incentives occur in the relevant market places, previous assessments indicate that demand response volumes should increase.

Large consumer will probably have lower costs and barriers to provide flexibility than smaller consumers, and we anticipate an increased share demand response from large consumers before potential from smaller consumers, especially households, due to higher costs of demand response for small consumers. However, one may argue that even for small consumers and households the price sensitivity may change from *no* to *some* flexibility due to increase in hourly metering, possibly increased share of spot price contracts and an increase in the supply of services by service providers and the opportunities offered by home automation.

4.4 Model analysis of the generation gap

In this section, we discuss how quantitative models can be used in capacity adequacy assessments. First, we give an updated estimate on the capacity margin in 2030. We then apply the The-MA power market model (cf. Appendix 2) to illustrate relevant simulations as part of an adequacy assessment, and to identify possible situations that should be investigated further. On the basis of simulations of a base case scenario and several sensitivity analyses, we seek to identify both the magnitude and frequency of a possible generation gap, plus what kind of capacity, if any, is critical in the Nordic market.

This section does *not* provide a complete adequacy assessment. It should rather be regarded as a first step in an adequacy assessment, cf. also the EC checklist. This first step is useful to identify the most critical parameters. First of all, a full adequacy assessment should apply a probabilistic approach, as discussed in chapter 2. We would also like to stress that adequacy assessments should not be based on market or system modelling alone. Model simulations will always be biased by the functionalities of the model, and by the assumptions made. Moreover, adequacy assessments should not disregard market conditions and dynamics. Hence, in addition to the model based analysis, the market's ability to produce sufficient capacity must be assessed, via profitability estimates, assessment of the potential demand response contribution, and the adequacy of the market design.

What assessment method to apply, also depends on the chosen reliability standard. For example, whether a de-rated capacity margin, a loss-of-load expectation, or an N-1 approach is used.

4.4.1 *Reference scenario assumptions*

In the analysis of the future capacity adequacy, we develop a reference scenario for 2030, based on the existing literature and extensive research conducted by THEMA.[22] The reference scenario is a reference for the subsequent analysis, although not an altogether unrealistic scenario. This is because the purpose of the exercise is not to represent a best-guess scenario, but a reference for the subsequent analysis. The reference scenario reflects the following main assumptions:

- *Loads*: The consumption level in 2030 is based on existing prognoses and our own analysis. When it comes to the load profiles, including peak load demand, there is substantial uncertainty. E.g., energy efficiency policies may alter the consumption patterns. We use load profiles based on historical time series. This approach gives relatively high peak loads, particularly for Sweden. The peak load in the model increases towards about 30 GW in a cold winter in Sweden, which yields a higher peak load growth than that of the assumption made by the Swedish TSO until 2025, but consistent with the chosen approach.
- *Wind power*: Our best estimate for installed wind power capacity is based on our Elcertificate market model and national policies and projections. We represent wind power generation patterns by historical time series, in order to capture the correlation between wind speeds in different areas, and the correlation between wind power and consumption.
- *Hydropower*: We have assumed no changes in reservoir hydropower capacity, compared to 2014. Note that although the potential of new reservoir hydropower is limited, there may be investments in additional generation capacity in existing hydropower stations (NVE, 2015). The availability of hydropower may be reduced during winter, due to ice, head variations, and unscheduled revisions. We use an availability of hydropower of 87%, as estimated by Nordel.[23] For run-of-river hydropower we assume that 90% of the inflow is must-run, i.e., forced generation during the hour of inflow, whereas the remaining 10% may be stored within the week.

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[22] THEMA Consulting Group conducts continuous market analysis of the Nordic and European power markets, and deliver price forecasts, market analysis and quantitative modelling expertise to the market players.
[23] https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/planning/070600_entsoe_nordic_PowerEnergyBalances2010.ppt

- *Nuclear capacities*: We assume that the three oldest Swedish nuclear reactors (Ringhals 1 and 2, and Oskarhamn 1) are phased out by 2030, as they reach their life length. The possibility that more Swedish nuclear may be decommissioned before 2030 is captured by a sensitivity with lower Swedish nuclear generation. We further assume that two Finnish nuclear reactors (Loiivisa 1 and 2) are phased out, and two new reactors (including Olkiluoto 3) are built. We assume a new nuclear plant in Lithuania (Visaginas) with a capacity of 1,350 MW. The installed capacities in 2030 are shown in Appendix table 1. The availability of Swedish nuclear generation is based on historical numbers, and is on average 86% in January. Finnish nuclear generation has an availability of 95%.
- *Other thermal capacities*: Assumptions about other thermal capacities are based on our best estimate, and are shown in Appendix table 1. We assume that condensing power plants are phased out when they reach their technical lifetime, and that power plants with heat obligations (CHP plants) are replaced by new capacity. Plants with known decommissioning plans are phased out accordingly. The availability of fossil fuel generation is set to 90% of installed capacity. Note that in addition to unplanned revisions and outages, the availability in the day-ahead market may be reduced in order to save generation capacity for the reserve markets. Currently, around 5% of installed generation capacity is used in the reserve markets.
- *Grid investments*: In the period up to 2030, there will be significant investments in the Nordic grid, in addition to new interconnectors to Continental Europe and the UK. The Baltic region will also be further integrated with the Nordic region, and a new interconnector between Sweden and Lithuania is expected by the end of 2015. A new cable between Lithuania and Poland is also under construction. Appendix 3 gives an overview of the assumptions for new interconnectors within the Nordic and Baltic region between 2015 and 2030, and for investments in new interconnectors out of the Nordic region. Note that final investment decisions have not been taken for all these interconnectors, so there is uncertainty about the future interconnection capacities. However, there are also discussions about building additional interconnection capacity. We have only included new interconnectors that we consider likely to be built, because experience shows that the time from planning to realisation of a new interconnector is typically very long. The assumptions about cable capacity developments are based on the grid development plans of the TSOs. We also assume that the current capacity remuneration

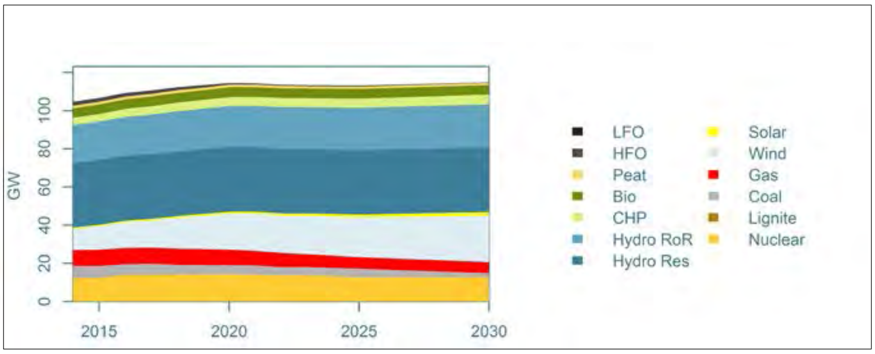
mechanism for trade with Russia is continued as today, and include a sensitivity with no Russian imports.

- *Neighbouring countries*: Neighbouring countries (Germany, Poland, Netherlands, the UK, etc.) are represented in the model with our best guess assumptions for generation capacities and loads, including normal wind and solar generation. In a full adequacy assessment, the effect of changes in for instance wind and solar generation in these countries should also be studied.

Substantial amounts of new generation capacity is expected towards 2030, yet, reliable thermal capacity is replaced by intermittent renewable energy. Figure 4.8 shows the installed generation capacity in the Nordics in the reference scenario. The majority of the new capacity is intermittent renewables, mostly wind power, as a result of continued support regimes. In addition, a large share of reliable generation capacity is phased out, in particular coal, and to some extent gas power, and Swedish nuclear capacity. The exception is Finland, where the share of nuclear capacity increases.

The assumptions for the reference scenario are based on publicly available information and current forecasts, but there is naturally uncertainty around the generation capacity and consumption estimates. Investments in new renewable generation are mainly driven by support schemes, whereas most investments in thermal generation are based on commercial considerations. Hence, changes in the renewable support schemes may change the resulting investments. Moreover, multiple factors affect investments in generation and consumption. For instance, fuel and carbon prices have a significant impact on the price level, which in turn may influence investment decisions. We have assumed a continuation of the current trend involving decommissioning of condensing power. We cannot rule out that CHP capacity may be replaced by heat-only due to low electricity prices. On the other hand, we have not accounted for generation capacity not included in current investment plans.

*Figure 19. Installed capacity in the Nordic region in the reference scenario**



* Extraction CHP plants are included in the numbers for gas, coal, lignite, bio, peat, LFO and HFO.

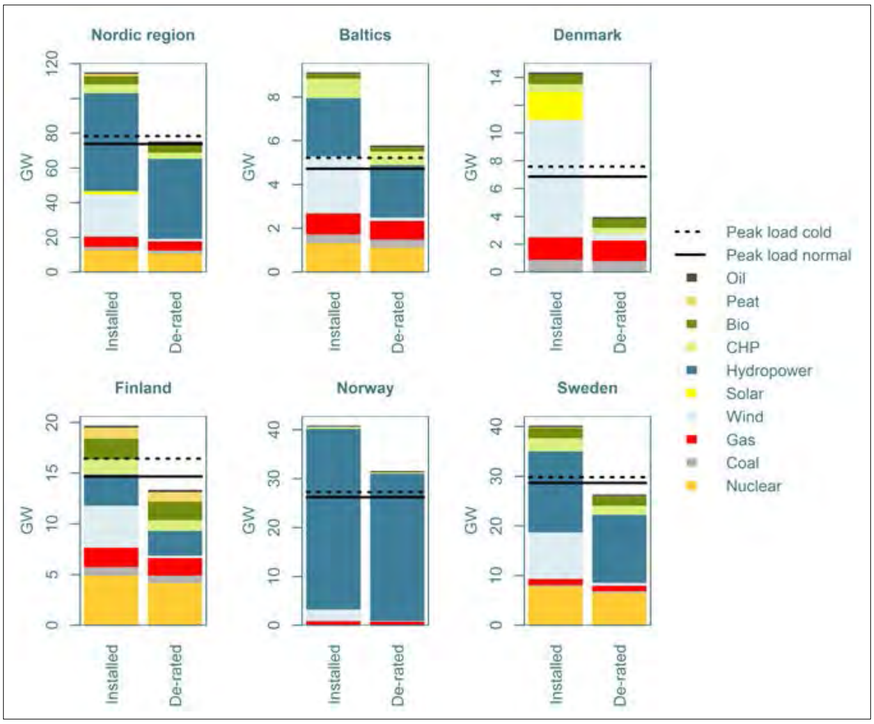
We do not model capacity saved for the reserve markets explicitly. However, we model the actual loads, rather than the consumption in the day-ahead market, so additional reserves to cover deficits should not be needed. The assumed generation capacities do not contain plants used in the peak load reserves or plants owned by the TSOs to handle grid disturbances (e.g., Fingrid currently owns almost 1 GW of generation capacity). By also reducing the availability of all generation technologies, we assume that there are sufficient reserves to stabilise the frequency in the system (such as primary reserves) and handle grid disturbances.

4.4.2 De-rated capacities in 2030

We first investigate the development in de-rated capacities for each country, for the Nordic region as a whole, and for the Baltic area.

Figure 4.9 shows peak loads, average available capacities and estimated reliable available capacity in 2030 in the reference scenario. The reliable available capacity is estimated by "de-rating" installed capacities, e.g., as done by the Swedish Energy Agency (2013). In this illustration, the reliable available capacity is six % of installed wind capacity and 70% of installed CHP capacity. Remaining technologies have availabilities as described in the reference scenario.

Figure 20. Capacities and peak loads in 2030 in the reference scenario



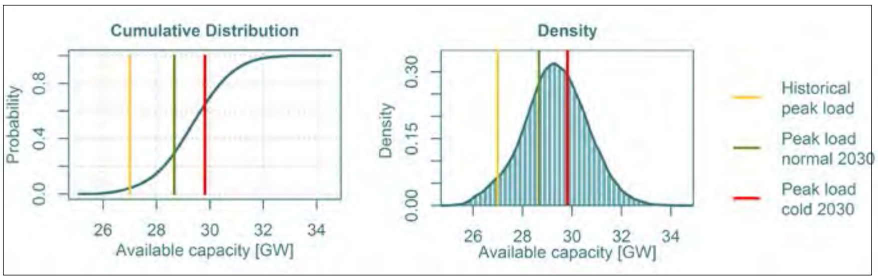
The figure indicates that the Baltic region and Norway are surplus areas during peak load, even in a cold winter. The large share of intermittent renewable energy in Denmark gives a low de-rated capacity, around half of peak load during a cold winter. Both Finland and Sweden have de-rated capacities lower than peak load, mainly due to the increasing share of wind power. The de-rating methodology indicates that the Nordic region as a whole may depend on imports during peak load in a cold winter.

The de-rating is a simple method, which does not provide a good description of the interactions between different technologies and market areas, and is a poor indication of the system's provision of flexibility and energy back-ups (cf. section 2.2). De-rating is therefore not sufficient to conclude on the system's capacity adequacy.

4.4.3 Probabilistic model approach

The de-rating of capacities indicates that Sweden may depend on imports during peak load in a cold year. A probabilistic simulation can be used to estimate the probability of this event. The availability of each technology varies, and using a probabilistic simulation, we obtain estimates of the risk of unwanted situations. Figure 4.10 shows a simulated probability distribution of the available capacity in Sweden in 2030 in the reference scenario. The left panel can be interpreted as the probability that less than a given generation capacity is available. In this figure, the availability of wind and nuclear follows a distribution based on historical profiles for daytime in January in the period 2007–2014, and the other technologies have availabilities as described for the reference scenario. We only account for stochasticity in wind power and nuclear availability, two important drivers of uncertainty. However, the figure does not show the effect of random import capacities and availability of the other technologies, which should be included in a full probabilistic assessment.

Figure 21. Simulated distribution of available capacity for Sweden in 2030



The loads that are not covered by generation needs to be covered by either imports or demand response. The results indicate that Sweden depends on imports and/or demand response during peak load with a probability of about 30% in a normal winter and 65% in a cold winter. In the worst case, i.e., a cold winter with minimum available capacity (about 24 GW), almost 6 GW of imports and/or demand response is needed. (In comparison, the expected import capacity into Sweden in 2030 is 11.6 GW.) Note that the probability for a power shortage will never be zero. If significant outages in the import capacity occurs at the same time as very high loads and very low generation availabilities, the Swedish system may experience challenges in meeting demand.

4.4.4 Model results

According to the definition of capacity adequacy, it is neither sufficient to simply investigate the capacity margin in each country, nor for the Nordic region in isolation. The system should be analysed as a whole, accounting for flows between countries, and the interactions between wind speeds, inflows and temperatures. In addition, one should examine whether there is sufficient energy back-up in the system, i.e., they system's ability to handle long periods of low winds and low temperatures, and whether the flexibility in generation and cables are sufficient to handle the variation in loads and intermittent generation. Publicly available studies have little emphasis on flexibility and energy back-up. In order to investigate the Nordic capacity adequacy in a broader perspective, we use the power market simulation model The-MA. A description of The-MA can be found in Appendix 2.

The model includes a detailed simulation of generation, whereas demand is modelled as completely inelastic. Hence the model identifies situations with a *possible* generation gap, but demand response is not taken into account. However, we identify hours and periods where the generation is not sufficient to meet the assumed load. Subsequently (in section 5.1.4), we discuss whether demand response can contribute to manage generation gaps.

In a normal year, i.e., a year with normal inflow and loads, the model does not identify any capacity shortages. In order to investigate the capacity adequacy in stress situations, we have developed six extreme, and analysed them with The-MA.[24] The probability of the occurrence of each of these cases is low. The first case is a cold and dry year situation based on the reference scenario. All the other cases are based on this cold and dry situation:

[24] We wanted to include a scenario with lower available flexibility in hydropower due to implementation of the water directive, but due to a lack of reliable data on the impact of the directive, such a sensitivity is not included.

1. *Cold and dry – reference:* This scenario represents the reference scenario in a dry and cold year. Inflows follow the historical profiles from 2010 (14% below normal in Norway and Sweden combined), and the peak loads are based on the "10-year" winter estimates. The inflow is also at the lowest level observed during the last ten years. Temperatures and inflows are correlated, although not perfectly. Hence, this case is expected to occur less often than every 10 years.
2. *Sea cable outages:* The cables between Finland and Sweden and between Finland and Estonia are out of operation. The availabilities on the cables between Finland and SE3 and Finland and Estonia have on occasions been low in recent years. All other assumptions as in the "Cold and dry – reference" scenario.
3. *Low Swedish nuclear:* Fifty % of the Swedish nuclear capacity is out of operation for the entire year. The available Swedish nuclear capacity is on average 3,386 MW in January in this scenario. The case represents a year with very low nuclear availability (less than 50%). In comparison, the availability of Swedish nuclear power was reduced by 5,000 MW (more than 50%) occasionally between December 2009 and April 2010 (NVE, 2010b). The case may also represent the impact of a nuclear phase-out in Sweden, if the capacity is not replaced. Although Vattenfall has recently declared the intention to phase out Ringhals 1 and 2, and Oscarshamn 1 before the reactors reach their lifetime, there are no concrete plans to decommission the remaining nuclear reactors before 2030. All other assumptions as in the "Cold and dry – reference" scenario.[25]
4. *No Russian import:* This case has no import from Russia to any country. The future of electricity trade with Russia is uncertain, and this scenario represents a situation where all trade is stopped. All other assumptions as in the "Cold and dry – reference" scenario..
5. *Interconnector outages:* This case contains outages of the interconnector between Zealand and Germany and one of the interconnectors between Sweden and Germany. All other assumptions as in the "Cold and dry – reference" scenario. The availabilities on the interconnectors have been occasionally low in

[25] The operating Swedish nuclear reactors in the reference scenario are Oskarshamn 2 and 3; Forsmark 1, 2, and 3; and Ringhals 3 and 4.

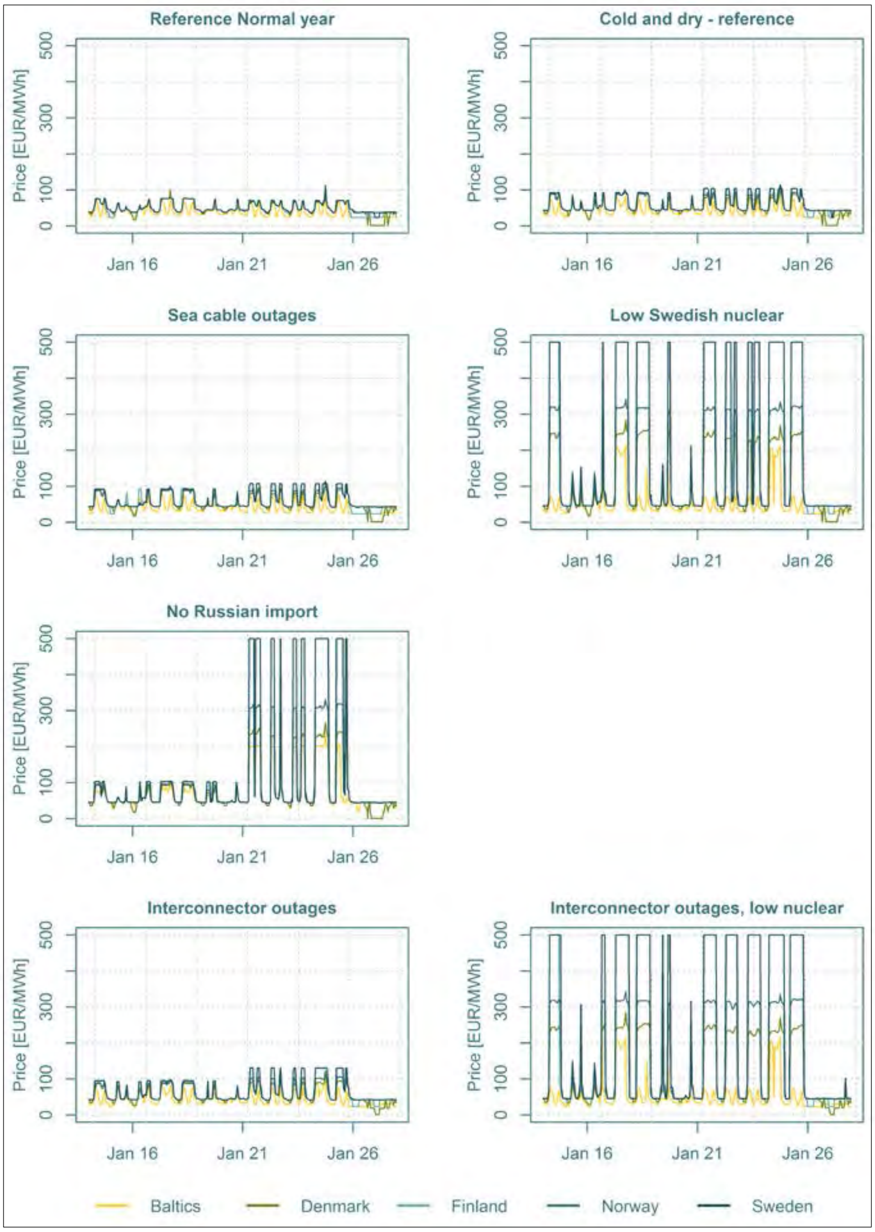
recent years. The day-ahead capacity on the cable between Sweden and Germany has in particular varied vastly.

6. *Interconnector outages and low Swedish nuclear:* This is the most extreme case, namely a combination of "Low Swedish nuclear" and "Interconnector outages". That is, 50% of Swedish nuclear capacity is not available and the interconnector between Zealand and Germany and one of the interconnectors between Sweden and Germany are out of operation. All other assumptions as in the "Cold and dry – reference" scenario.

We obtain information about situations where the system is stressed to its limits by using historical time series for loads, wind generation and inflows. In the simulations, week four is particularly challenging, due to high loads and occasionally low wind speeds. Week four hence represents a stressed situation in 2030.

The simulated prices for weeks three and four in 2030 are shown in Figure 4.11 for the reference scenario and the extreme cases. Week four is the only period where the model identifies a generation gap. The price is set to 500 EUR/MWh if a generation gap occurs. Generation gaps occur only with low Swedish nuclear generation, or with no imports from Russia. Below is a description of the results from each scenario.

Figure 22. Simulated prices in weeks 3–4 in 2030 (averages over bidding zones in each country)



Cold and dry – reference

There are no capacity shortages in the Cold and dry – reference scenario. The hourly price reaches 100 EUR/MWh at day-time during week four. Figure 4.12 shows the generation and loads during week four. Friday of this week is particularly challenging, due to high loads and very low wind speeds. Denmark depends on about 3 GW of imports, almost half of the system load. Moreover, both Sweden and Finland are net importing this day, whereas Norway is exporting a small amount.

The Baltic region has a strong balance, partly due to the new nuclear plant and substantial hydropower capacity. Furthermore, the Baltic region partly acts as a transit region for flows from Poland, Russia and Belarus into the Nordic region. The flows on the cables between the Baltic region and the Nordic region are therefore mostly directed towards Sweden and Finland during high load hours.

Figure 23. Generation and consumption week four of 2030 in the Cold and dry – reference scenario

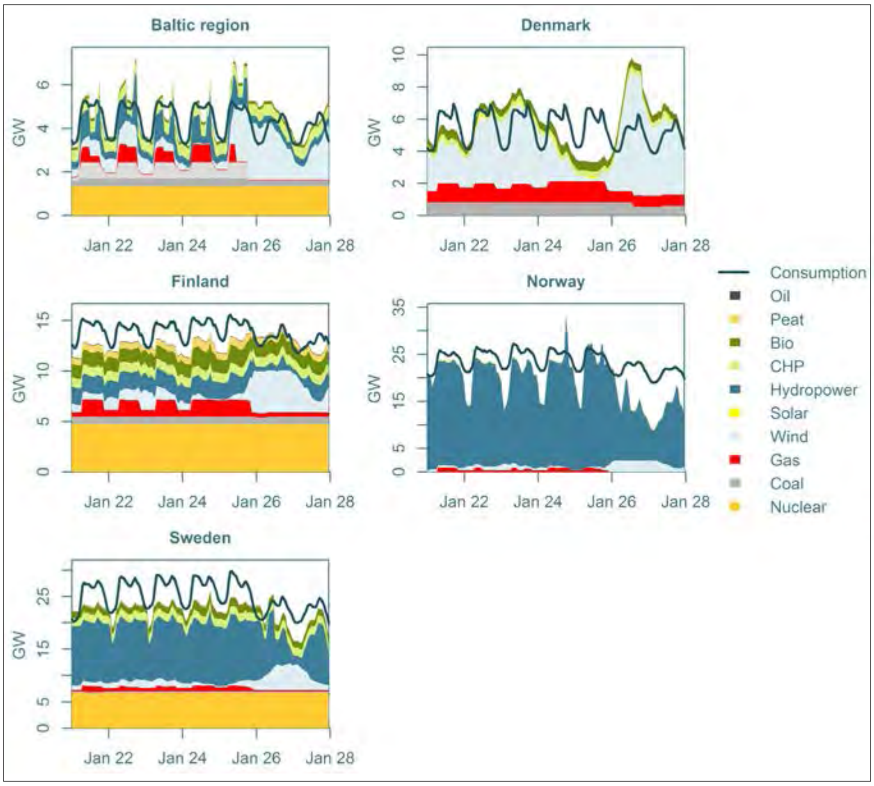
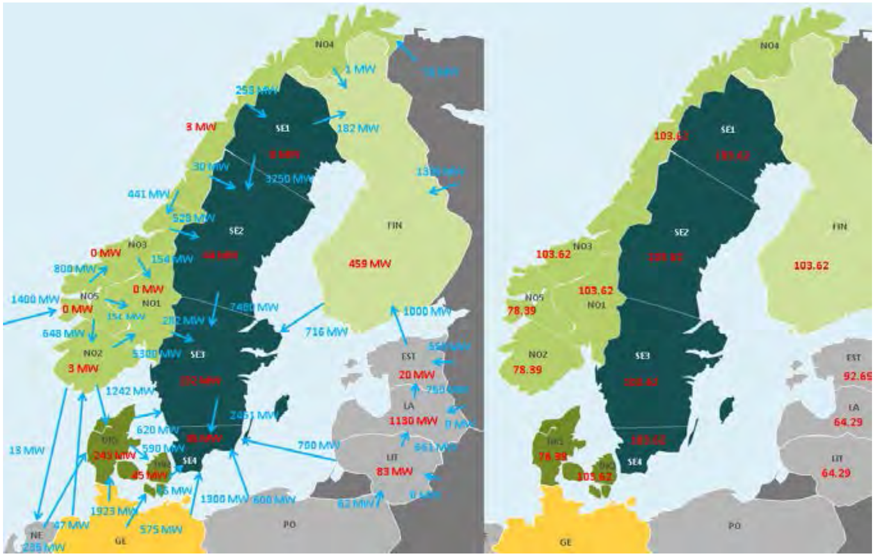


Figure 4.13 shows the flows and prices at 8–9 am on Friday of week four, the hour with the highest load. The flows are directed towards Eastern Norway, Southern Sweden and Eastern Denmark. Due to low wind speeds, Denmark and Southern Sweden are importing large amounts from Norway, Finland, Germany, Poland and the Baltic region. Norway has net exports, and acts as a transit region for power from the UK. Finland has net imports, and acts as a transit country for westward

flows towards Sweden. The simulated flow pattern is similar to the typical pattern today (see Figure 5), except for a stronger balance in Finland, which contributes to the exports towards Southern Sweden in the model simulations.

Figure 24. Friday 8–9 am week 4 in the Cold and dry – reference scenario. Left: Flows (blue numbers) and capacity margins (red numbers). Right: Prices (EUR/MWh)



In this high load period, all of the flexible Norwegian hydropower is utilised. There is sufficient transmission capacity to utilise all flexible generation capacity. Moreover, hydropower provides the cheapest flexibility, and is used to level out most fluctuations in wind power and consumption, as can be seen in Figure 23. The figure also reveals that gas power is partly used to level out variations between day and night. In the Baltic region, even coal generation is partly used for day to night flexibility in the most stressed period. This is the most expensive source of flexibility in the model. In conclusion, there is no indication of insufficient flexibility in the simulations, mainly due to the large share of flexible hydropower.

There is no indication of insufficient energy back-up, i.e., inability to handle prolonged periods with low inflows, low wind speeds, and high loads. Compared to today, the interconnectors to Continental Europe and the UK provide additional energy back-up in a dry year. However, The-MA is a perfect foresight model, which may give inaccurate hydropower disposal in a year with abnormal hydro inflows. A cold period by the end of an unexpectedly dry winter may cause challenges to meet demand in the hydro-dominated regions, in particular in Norway. However, the interconnector capacity into Norway is expected to increase by 3,500 MW, providing additional back-ups from Germany, Netherlands, and the UK. The detailed impact of a cold period by the end of a dry winter should be studied in a full capacity assessment.

Sea cable outages

There are no capacity shortages in the event of significant outages of the sea cables into Finland. Although Finland may depend on imports during peak load, the system seems robust towards reduced import capacity from Sweden. In the normal situation, Southern Sweden handles peak load partly by imports from Finland, partly transited from Russia and the Baltic region. However, Sweden is also able to handle peak load situations with reduced imports from Finland. The sea cable outages result in slightly higher prices in Finland and Sweden during January, but no generation gap.

Low Swedish nuclear

In the event of a significant reduction of Swedish nuclear generation, Sweden and Norway may face a generation gap. As a result of low nuclear generation, a substantial generation gap of almost 2.7 GW is identified by the model, cf. Figure 4.14. The simulated generation gap for the Nordic region is shown in Table 4.4. The most stressed areas are the net-importing regions of Eastern Norway (NO1), and the two southernmost zones of Sweden (SE3 and SE4). The simulated timing of the capacity gaps should not be interpreted as exact. Parts of the hydropower capacity has limited flexibility (for instance within one week). However, the cost curve of demand response in 2030 is highly uncertain, and we discuss whether demand response could help handle the situation in Section 5.1.4.

Figure 25. Generation gap in weeks 3–4 in the Low Swedish nuclear scenario in 2030

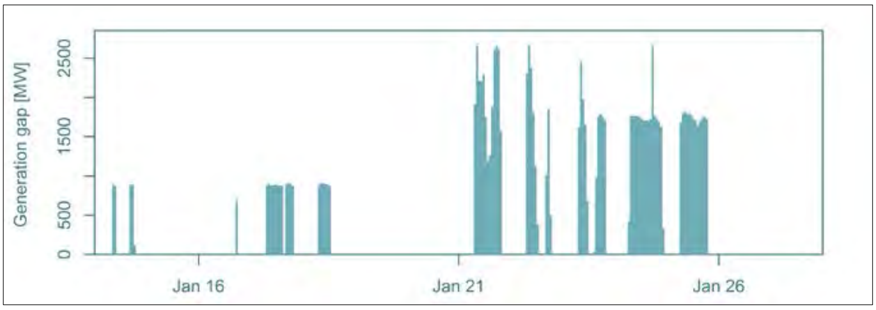
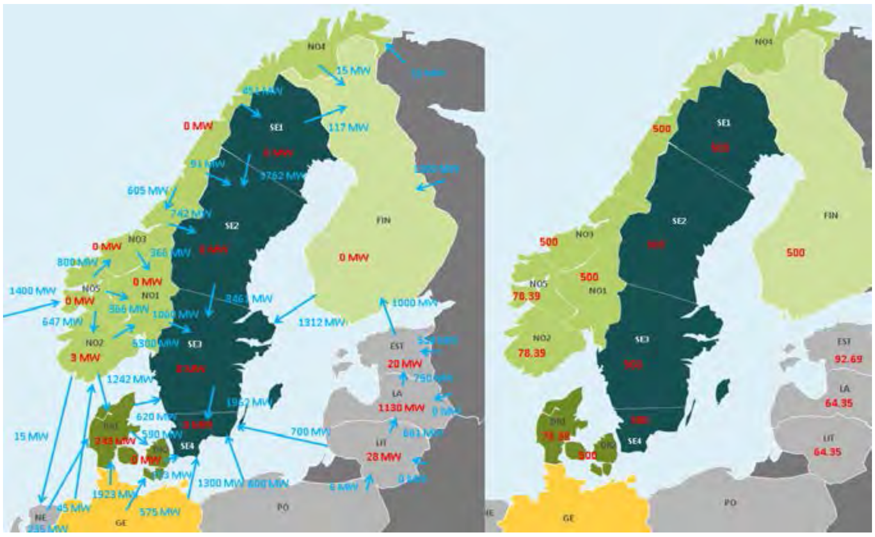


Table 12. Generation gap in the Nordic region the Low Swedish nuclear scenario in 2030

Total generation gap (energy)	Hours with generation gap	Maximum duration	Maximum gap
128 GWh	87 hours	17 hours	2,663 MW

There are no bottlenecks between the Swedish zones, Eastern Denmark, Finland and Eastern, middle, and Northern Norway, as shown in Figure 4.15. The figure shows the hour with the highest hourly load. All the mentioned zones experience very high prices, and load reductions in any of these zones would help mitigate the generation gap. The flow pattern is similar to the flows in the reference scenario. However, the capacity margins are significantly reduced. There is a bottleneck between Western Denmark and Eastern Denmark and between Western Denmark and Southern Sweden. Hence, available capacity from Western Denmark (and from the continent) cannot be canalised to mitigate the power shortages in Southern Sweden. According to Energinet.dk (2014), there are no plans to increase the current capacity between Western Denmark and Eastern Denmark or Western Denmark and Southern Sweden.

Figure 26. Friday 8–9 am week four in the Low Swedish Nuclear scenario. Left: Flows (blue numbers) and capacity margins (red numbers). Right: Prices (EUR/MWh)



There is also a bottleneck between Southern Norway and Eastern Norway. At the same time as there is a significant generation gap in Eastern Norway and Southern Sweden, there are net exports out of Southern Norway. Hence, the generation gap would be smaller with more transmission capacity between Southern and Eastern Norway.

Finland is a net importing zone during the high load hours. However, large transmission capacity to Russia and the Baltics ensure the capacity balance in Finland, and enables exports from Finland towards Southern Sweden.

No Russian import

Stopping all imports from Russia may cause a capacity shortage in the Nordic region. The Nordic region is directly affected when removing imports from Russia into Finland and Norway. Additionally, the flow from Estonia to Finland is reduced by approximately 250 MW during peak load, because the Baltic region also suffers from the missing Russian imports. The deficits of Southern Sweden and Eastern Norway cause generation gaps in the simulations, as shown in Table 13. The maximum gap is however less than 1,000 MW.

Table 13. Generation gap in the Nordic region in the No Russian Import scenario in 2030

Total generation gap (energy)	Hours with generation gap	Maximum duration	Maximum gap
34 GWh	43 hours	12 hours	911 MW

Interconnector outages

We do not identify hours with a generation gap in the case where we assume outages of two of the interconnectors between the Nordic region and Germany. We suspect that outages on other cables will have similar effects (the cables to the Batlics, the Netherlands, etc), but the details are not studied.

Interconnectors outages and low Swedish nuclear

This is an extreme case with a very low probability, as it implies significant and simultaneous outages of interconnectors and nuclear capacity during a cold and dry winter. In such a case, it is not surprising that the simulation shows a significant generation gap. The pattern is similar to the results from the low Swedish nuclear scenario, yet amplified, as shown in Table 4.6. Again, the deficits occur in Southern Sweden (SE3 and SE4) and Eastern Norway (NO1). The largest generation gap is more than 5,000 MW.

Table 14. Generation gap in the Interconnectors outages and low Swedish nuclear scenario in 2030

Total generation gap (energy)	Hours with generation gap	Maximum duration	Maximum gap
272 GWh	124 hours	17 hours	5,303 MW

Summary of model results

The simulations indicate that the risk of generation gaps increase if large amounts of Swedish nuclear power are phased out earlier than planned, or if Russian imports are reduces substantially. The large share of hydropower in the Nordic and Baltic regions, and the high degree of interconnectivity, provide flexibility to handle large variations in loads and wind power generation.

Despite the large share of intermittent renewable sources, generation gaps do not occur in Denmark in the model simulations. This is due to ample interconnector capacity. However, if multiple interconnectors fail during a period of low wind speeds, Denmark may experience generation gaps.

The model simulations indicate that Finland may still depend on imports during peak load in 2030. The interconnector capacity to Sweden, Norway, Estonia and Russia is however sufficient to cover the deficit even in a very cold winter. Significant outages in interconnector capacity (and/or equivalently, significant generation capacity outages) increase the risk of generation gaps in Finland.

Norway has large amounts of flexible hydropower in addition to large interconnector capacity in 2030, and faces few capacity challenges. However, the model identifies a risk of generation gaps in Eastern Norway in the cases when Swedish nuclear generation is substantially reduced. The Southern and Western regions of Norway are surplus zones with ample interconnector capacity. In extreme situations, however, the surplus of these regions cannot fully be transferred to Eastern Norway, and further towards Sweden, due to limited grid capacity.

The results indicate an increase in the risk of generation gaps if large amounts of Swedish nuclear power are phased out earlier than expected, and if this capacity is not replaced by new reliable generation capacity. The risk increases during a cold and dry winter, and will be amplified if there are interconnector outages at the same time. Outages in large generation plants will have the same effect.

Discussion of model results

The model simulations indicate that the Nordic system is quite robust to changes in wind power, inflows and loads in 2030 in normal situations. However, generation gaps may occur if the nuclear capacity and/or interconnector capacity is significantly reduced. In the simulations, we treat both the generation and consumption as static, that is, independent of the developments in the system. We therefore need to investigate whether the market may provide incentives to invest in increased in generation capacity and/or demand response.

The probability of a capacity shortage will never be zero. No generation capacity or interconnector has a reliability of 100%, and several outages can occur simultaneously. The probability of a cold and dry winter with low wind speeds in combination with substantial generation capacity or interconnector outages is very small, yet not zero. Carrying out costly measures to reduce the probability or consequences of such an event may not be worth the benefits, because the combination of such events is extremely rare. This risk must be assessed in terms of LOLE and/or EEU values in order to determine whether the cost of measures is justified. We return to this issue below (in section 5.1.4). Moreover, we have yet to discuss possible market responses to future capacity challenges.

5. Policy and market measures for capacity adequacy

The model simulations indicate that the capacity adequacy in the Nordic market is generally quite robust, although some extreme cases in which the risk of capacity shortage increases are also identified. Our model simulations are however simplified and do not account for all possible outcomes. Moreover, we have not attempted to assess the probability of different extreme situations.

Model based analysis should in any case be used as a first step in capacity adequacy assessments. All models are simplifications of the actual market, and model results tend to be biased because typically a limited number of scenarios that can be run, the input assumptions (e.g. about CO_2 and fuel prices) and the correlation between variables are uncertain, and the full variety of market dynamics are often not adequately captured.

Hence, when The-MA identifies generation gaps, it does not imply that the system will be unable to equate supply and demand. Rather, the identified shortages indicate a need for demand response and/or investments in generation capacity. In this section, we turn to the market's ability to bridge the identified generation gaps.

In this chapter, we discuss whether the Nord Pool energy only market design and market regulations can be strengthened when it comes to providing incentives for capacity adequacy. The discussion is in line with the guidance on market intervention from the European Commission (EC checklist, see Appendix 1). In the first section of this chapter we discuss the assessment of the generation gap (capacity adequacy) based on the analyses above, and as described in the EC guidance. In the second section, we discuss to what extent market and regulatory barriers may adversely affect capacity adequacy in the Nordic market.

5.1 Assessment of generation gap

According to the EC checklist (see Appendix 1) assessment of a generation gap should, in essence, take into account

- what kind of capacity is needed (or missing)
- how interaction with neighbouring markets is taken into account
- how the development of the internal energy market (IEM) affects capacity adequacy
- the profitability of capacity in the market
- the role of demand flexibility
- the value of lost load.

Based on the results from previous chapters we discuss to what extent those "criteria" are fulfilled in the Nordic market in the following sections.

5.1.1 Kind of capacity needed

As highlighted in the introduction, capacity adequacy is not necessarily restricted to the availability of sufficient capacity during peak load. The model-based analysis above has identified the kind of capacity that may be needed by distinguishing between peak load capacity, flexible capacity and energy back-up capacity. When an increased risk of capacity adequacy challenges in the Nord Pool market area is identified, we do however find that it is most likely related to peak load capacity. Energy back-up seems to be adequately provided by hydropower with reservoirs and import capacity from other markets. Moreover, the model simulations suggest that flexible hydropower is able to manage the need for flexibility in the market. It should however be noted, that our model simulations are simplified and do not account for all possible outcomes.

The analysis above is not based on a full probabilistic study, nor is it based on a defined reliability standard. We would however note that the assessment depends on how the reliability standard is defined. Our assessment is based on the definitions provided in chapter 2, but not on a reliability standard in terms of LOLE or a probabilistic approach to the system characteristics going forward. Moreover, there are no common principles for the definition of a reliability standard in the Nordic control areas, and all areas have not defined a clear reliability standard. For example, as reported by the Danish TSO, Energinet.dk has the responsibility to “ensure sufficient capacity in the interconnected system”, but “sufficient” is not clearly defined.

5.1.2 Interaction with neighbouring markets and the impact of the IEM

The utilization of interconnector capacity has improved with increased market coupling over a larger region, encompassing several countries. Indirectly, the Nordic region is coupled with the larger interconnected market area of the IEM. This is taken into account in the model analysis.

Other possible market developments are not fully taken into account. Flow-based market coupling and improved bidding zone delimitation are likely to increase the volume and improve the efficiency of trade within the market, including provision of better long-term price signals for investments. At the same time, the implementation of capacity mechanisms may have the opposite effect. We elaborate on these points below.

Market integration, market coupling and the impact of the IEM

The The MA model covers the Nordic market and the surrounding market areas. Trade is determined by hourly market prices, i.e. full market coupling is assumed.

The model analysis shows that the Nordic area is likely to depend on imports during extreme peaks and in very dry years (energy). We do not find that the import dependency poses a particular problem, especially since the Nordic region is well integrated with highly diversified import opportunities. After 2020, the Nordic region will have interconnectors to Great Britain (Norway), Netherlands (Denmark and Norway), Germany (Denmark, Norway and Sweden), Poland (Sweden), Lithuania (Sweden), Estonia (Finland) and Russia (Finland and Norway). Apart from Russia, all of these markets are part of the IEM, and cross-border electricity exchange is based on hourly market prices. The latter applies to the Finnish imports from Russia as well, although the implementation of a capacity charge in Russia has increased day-time prices and reduced imports in recent years. However, the import opportunity from Russia prevails, although the costs have increased.

The Baltic area is likely to have a positive capacity margin during peak load, i.e. to be an export area.

Flow-based market coupling and bidding zone delimitation

Implementation of flow-based market coupling and improved bidding zone delimitation is likely to make electricity trade and price signals more efficient in areas surrounding the Nordic market. In essence, such developments should improve locational price signals and the basis for investments in generation, consumption and grid capacity, including flexible capacity and reserves. To what extent flow-based market coupling and bidding zone delimitation will be beneficial, depends on the detailed design and to what extent locational price signals are passed through to end-consumers.

Capacity Remuneration Mechanisms in adjacent markets

Interventions in spot market areas in interconnected markets may also affect capacity adequacy in the Nordic market. GB, Poland and France have implemented Capacity Remuneration Mechanisms (CRM), and Germany is discussing to follow suit. Such mechanisms may be designed in different ways, and the impact on the Nordic market is ambiguous. Pöyry (2014) points out that many proposed CRM Schemes are simplistic and may replace market risk with regulatory risk, dampen price peaks, undervalue flexibility and distort cross-border trading and demand response incentives.

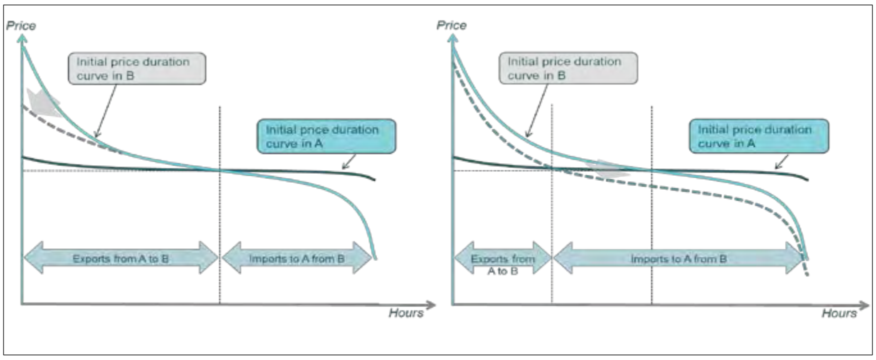
On the one hand, CRMs are prone to yield over-capacity. The analysis in THEMA *et al.* (2013) shows that spill-over effects of over-capacity in one market (with CRM) to another market (without CRM) is to reduce investment incentives in the market without CRM. Hence, the capacity adequacy in the non-CRM market may be adversely affected. The impact depends on the correlation between the markets however, and to what extent the CRM mainly affects peak load prices in the CRM market.

Figure 5.1 illustrates the main impacts of CRM on the price duration curve in the "foreign" market (market B). We assume that the price duration curve is steeper than in the Nordic hydro-based system (market A). CRM may lower the entire price duration curve in B and/or it may particularly reduce peak load prices:

- If the CRM reduces medium-load prices (right panel), prices in the Nordic area will be reduced as well, and thus the general investment incentives will be weaker.
- If the main effect of CRM is to reduce peak prices (left panel), the Nordic price level will not be directly affected. However, the profitability of interconnectors will be negatively affected, and hence interconnector investments may be reduced in the long term. This may in turn increase the risk of new renewable (intermittent) generation yielding low prices in the Nordic and thereby reduce investment incentives for commercial capacity and demand side response in the long run.

It is not very likely that a CRM scheme will only affect peak load prices, particularly in the long run. Hence, as CRMs are prone to induce increased capacity investments, they are also prone to adversely affect the capacity adequacy in adjacent markets in the long run. Moreover, the adverse effects are likely to be larger, the higher the price correlation between the markets. This implies that investment incentives in Denmark are more likely to be adversely affected by a CRM scheme in Germany than the rest of the Nordic market. Modelling of trade between Finland and Russia, indicates that the Russian capacity mechanism reduces exports to Finland during peak load in the short term, and moreover, creates adverse investment incentives between the markets (Viljanen *et al.*, 2013).

Figure 27. Impact of capacity remuneration mechanisms in individual markets



CRM schemes may make provisions for participation of cross-border capacity. The framework for such participation may be designed in a way that mitigates the adverse effects of individual CRM schemes (see e.g. Tennbakk and Noreng, 2014). ACER guidelines and the network code on capacity adequacy and congestion management implies that CRMs should take cross-border contributions to capacity adequacy into account and cater for cross-border participation.

5.1.3 Profitability of generation capacity

What is *the market* expected to provide in terms of investments, decommissioning and refurbishments?

In the simulations presented in Chapter 4, we did not model investments in new generation capacity. In this section, we investigate whether the current markets provide incentives to invest in generation capacity.

If additional peak generation capacity is needed, a technology with high reliability should be chosen. The Nordic system has plenty of flexibility, so additional capacity need not necessarily be highly flexible. However, in the model simulations we find that the price level is generally fairly low, with occasional peaks in extreme events. Hence, gas turbines will probably be the most adequate technology for additional reliable capacity, because of relatively low investment costs. Söder (2015) also points out that gas turbines are the cheapest technology for investments in generation capacity that is only in operation a few hours each year.

Two recent studies, by NVE (2015) and Elforsk (2014), respectively, estimate the levelised cost of energy (LCOE) for new generation capacity in Norway and Sweden. Table 5.1 shows estimates for the fixed costs of a gas turbine. The table also shows the range of the estimates in a survey conducted by DIW (2013).

Table 15. Estimated annual fixed costs of a gas power plant in 2030.[26] All numbers in EUR/MW

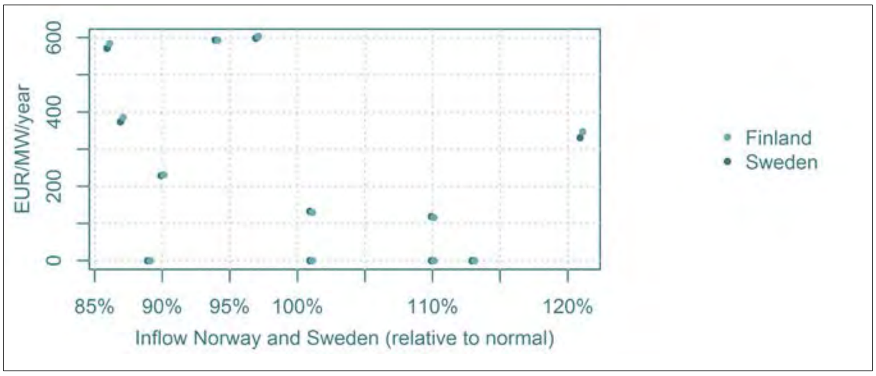
Source	Investment cost	Annualized investment cost[27]	Fixed annual operational costs	Total annual fixed costs
NVE (2015)	524,118	33,550	17,647	51,197
Elforsk (2014)	484,211	30,996	6,842	37,838
DIW (2013)	390,000–730,000	24,965–58 629	11,900–19,500	36,865–66,229

Figure 5.2 shows the simulated day-ahead market revenue minus variable costs of a gas turbine in Southern Sweden and Finland, respectively, with varying inflow on the horizontal axis. The resulting revenues are very small, and not sufficient to make such investments profitable. In more stressed situations, the value of peak capacity turbines increases. However, even in the low nuclear scenario, the model simulations do not yield very high revenues for a gas turbine, and barely sufficient to cover the fixed costs for that year. The turbine is only used in hours with a generation gap, so the utilisation is still quite low. The simulations also indicate that investments in new combined cycle gas turbines (CCGT) are not profitable, due to low utilisation.

[26] Exchange rates of 8.5 NOK/EUR and 9.5 SEK/EUR are assumed.

[27] We use an economic lifetime of 25 years and a weighted average cost of capital of 4%, following NVE (2015). We have not taken into account any cost reductions, however, this technology is mature, and the future learning rate is expected to be small.

Figure 28. Day-ahead market revenues after variable costs of one gas turbine in Southern Sweden and one in Finland in the reference scenario for 2030 with varying inflow



The revenues from existing strategic reserves are not sufficient to cover the fixed costs of a gas power plant. Table 5.2 shows the estimated current prices of the capacity mechanisms in the Nordic region. A scenario with investments in gas power plants hence requires substantially higher prices for peak load reserves, since the revenues from the day-ahead market are not sufficient to cover the fixed costs. However, the current prices in the strategic reserves of Sweden and Finland reflect the costs of extending the lifetime of existing old plants used as a reserve rather than the investment costs of a new plant, and, in Sweden, even the cost of demand response in the reserve.

Table 16. Historic prices for strategic reserves

	Swedish strategic reserve 2014/2015	Finnish strategic reserve 2014	RKOM Norway 2013/2014
Estimated price [EUR/MW/year]	7,600	21,280	3,000–4,000

Sources: SvK, Fingrid and Statnett.

A gas turbine may also earn additional revenues from the reserve markets. However, a gas turbine that is seldom in operation cannot participate in the market for primary reserves or secondary and tertiary reserves for downwards ramping. Additionally, in most of the year, hydropower would be a cheaper for the all types of reserves. Thus, the potential revenue from reserve markets for a peak load turbines is probably limited, and not likely to make a gas turbine profitable in the reference scenario.

Investments in upgrades of Norwegian hydropower generation may however contribute to mitigate identified generation gaps. In 2007, the potential for upgrades and extensions of existing Norwegian hydro power was estimated to 12.6 TWh at an investment cost less than 3 NOK per kWh annual consumption (about 23 EUR/MWh) (NIVA, 2007).[28] The increased generation capacity needed to realise the increased potential was 4,000 MW, according to the study. Moreover, the study states that if needed, the generation capacity could be increased further. Hence, increased Norwegian hydropower capacity may be sufficient to cover a deficit in extreme events, such as in the Low Swedish nuclear and low interconnector capacity scenario. This scenario resulted in a generation gap of up to 5,300 MW. Additional grid investments may also be needed in order to transfer the power towards Eastern Norway and Southern Sweden.

The cost of hydropower upgrades are highly dependent on local conditions, so making accurate profitability analyses difficult. However, if the system changes for instance due to a large-scale nuclear phase-out, higher peak prices would be expected, making capacity upgrades more profitable.

5.1.4 Demand flexibility and the value of lost load

Demand flexibility

The model results indicate that in extreme events, there is a need for demand response to close the generation gap. The studies presented in chapter 3, estimate the potential for demand response in the Nordic region to 12,000 MW. Some of this potential is already price sensitive or participating in the market places, but we also know that at least 4,000 MW is currently not present (mainly buildings) in the market. Hence, the potential for increased demand side response is estimated somewhere between 4,000 and 12,000 MW.

Although the potential for demand response may be substantial, most assessments do not take into account the characteristics of the potential (response time, duration of disconnection, resting time etc.) nor the costs of utilising the potential. As a result, the potential for demand response, and in particular the cost of demand response, is highly uncertain.

According to the model simulations, however, demand response in some hours per day seem to be sufficient to manage capacity shortage situations. Reduced loads a few hour per day seems possible for buildings without reduced comfort for inhabitants or workers. For industry, the possible duration and timing of load reductions will vary. The metal

[28] Assuming 4,000 full load hours, an economic lifetime of 25 years and a 4% discount rate.

industry and greenhouses are examples of industries that may handle load reductions for a few hours without (large) production losses. Traditionally, the industry has provided the demand flexibility in the Nordic market, mainly in the Finnish and the Norwegian markets.

The current low demand side activity in the market may be explained by the relatively low electricity price levels, small price variations, and low frequency of high price peaks. However, when looking at historical demand curves in the market, some parts of the available demand response is represented in the market during hours with high loads (and hence high prices). Moreover, earlier peak price situations indicate that the demand side does become more active when prices peak several times within a shorter time period (as e.g., noted by Bye *et al*., 2010). As future price spikes may be both more frequent and much higher than the ones experienced thus far, we do not know the volumes of demand response unleashed at different price levels. However, demand response will probably not increase over night if price spikes occur suddenly.

The likelihood that demand will respond to prices will also increase if enabling technology is installed and the consumer is faced with price signals at an hourly level. Changes in technology, regulations and market conditions may profoundly change the behaviour of electricity end-users in the future.

Demand response may be a cheaper way to handle potential generation gaps, compared to investments in generation capacity. As discussed in Section 4.3.2, significant Danish demand response can be activated with a yearly payment between 54,000 and 80,000 EUR/MW/year, according to Dansk Energi Analyse (2010). Hence, the cost of Danish demand response is in the same order of magnitude as the cost of a gas turbine. Further, we find that there probably is a significant potential for demand response in the industry in the other Nordic countries. Thus, the studies indicate that the demand side is able to adapt if the market value of demand side flexibility increases.

Value of lost load

The EU checklist requires that the capacity adequacy assessment takes the value of lost load (VOLL) into account. We interpret “lost load” in this connection as (involuntary) curtailment of loads, i.e. demand reductions that are not market-based. The value of lost load must be assessed in relation to the probability that loads will be lost, i.e. it should be related to the definition of reliability standards. The implicit reliability standards in the Nordic area do not appear to be based on a clear calculation of the value of lost load.

Above, we argue that sufficient demand response is likely to be activated via market prices in scarcity situations. Activation requires that the demand side is represented in the market with flexible bids, be it in Elspot, Elbas or in reserve markets. Hence, we expect the market bids to reflect the value of lost load.

If the balance between supply and demand cannot be established via the market places or in real-time, loads will be lost through curtailment. In the case of curtailment, the value of lost load may be very high, e.g. as reflected in the Norwegian KILE costs. Market based load reductions generally imply efficient voluntary "curtailment", and that loads with lower values will be reduced.

A LOLE (or EEU) based reliability standard should not be regarded independently of the VOLL (Value of lost load), and the VOLL is difficult to assess as long as demand response is highly uncertain. Moreover, today's VOLL estimates are not likely to be representative for VOLL in the future.

5.1.5 Summary of section

If the Nordic market will experience a generation gap in the future, it is most likely to occur during peak load. The generation gap does not necessarily need to be filled by increased generation capacity in the Nordic area, however:

1. Increased market integration and improved price formation in adjacent markets contribute to a strengthening of capacity adequacy, although ill-designed CRM schemes in adjacent markets may yield partly adverse effects.
2. Although it is probably not commercially viable to invest in new gas turbine capacity, it may be profitable to increase the generation capacity in existing hydropower if the value of flexibility increases.
3. Demand flexibility may play a more substantial role in the market if the value of flexibility increases, and may turn out as a cheaper alternative than additional investments in generation capacity.

In summary, there should be sufficient resources in the system to fill the possible generation gap.

We now turn to the markets' ability to mobilise these resources.

5.2 Causes of adequacy concerns: Regulatory and market barriers

As will be apparent from the discussion below, there are many different regulations that may affect investments and hence, capacity adequacy. Within this project, we cannot hope to capture all aspects in detail. Hence, the discussion could serve as a starting point for a search for disincentives within the national regulations, particularly when it comes to barriers to investments in peak load and flexible generation capacity, and in demand response. Hopefully, however, we capture the most significant sources of disincentives in the discussion below.

5.2.1 Retail price regulations

Retail prices are not regulated in any of the Nordic markets. However, end-user prices are subject to levies that may mute the price signal from the market.

Fixed price contracts

The existence of fixed price contracts is often cited as a barrier to demand response. However, even consumers with fixed price contracts may be incentivized to provide flexibility through separate arrangements where flexibility is bid into the market. For example, with smart meters and hourly metering, there is no reason why an aggregator cannot offer a flexibility contract remunerating load reductions, for example to be bid into the intraday market, to consumers with fixed price contracts, if both parties find it economically interesting.

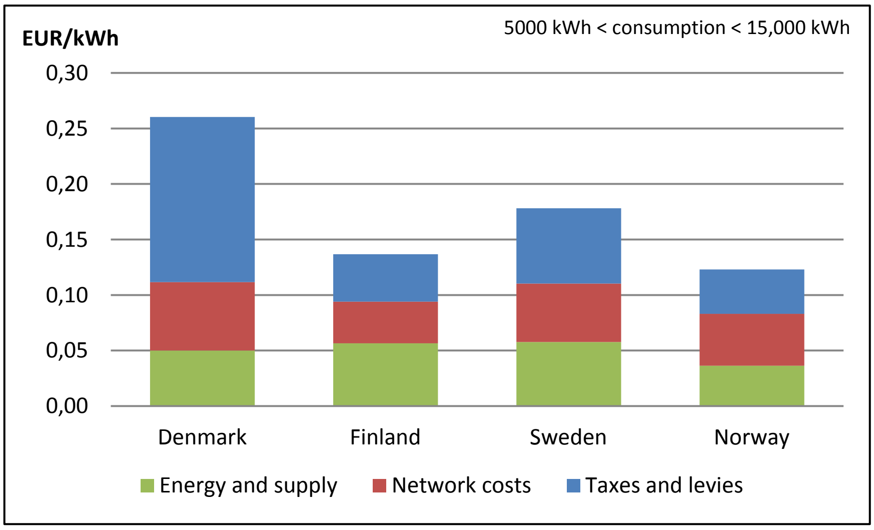
Different energy contracts will give different incentives for demand flexibility. The first aim for governments should be to make sure regulations *do not hinder* the retailer's possibility to develop and offer electricity contracts that promote demand response, and to remove any unnecessary obstacles for the consumer to choose such contracts. That being said, it should be up to the consumer to weigh the costs and benefits of fixed price contracts vs. spot price contracts, i.e. fixed price contracts should by no means be banned.

Taxes and levies

Connect *et al*. (2014) hold that tariffs, fees and cost allocations can bias the operative decisions of market participants. In particular, the exemption of so-called auto-production (industry) and heterogeneous taxation in the power, heat and transport sectors can lead to disadvantageous behaviour with regard to the power system as a whole, cf. also THEMA (2014a) on the economics of energy efficiency. In Germany, a dynamic allocation of the Renewable Energy Law (EEG) surcharge is currently discussed in the context of setting incentives more efficiently from a system-wide perspective.

Figure 29 illustrates the composition of the electricity bill for households and large industry in the Nordic countries. In the Nordics, prices for small for large industry are relatively equal, while prices for households vary significantly, mainly due to different levels of taxes and levies.

Figure 29. The total price of electricity for Nordic consumers



20,000 MWh < Consumption < 70,000 MWh

Source: THEMA (2014a).

Taxes and levies may enhance or mute price signals and is discussed in TemaNord (2014). The main taxes on electricity usage are VAT and electricity levies. Both VAT and levies are substantially lower for the industry than for small electricity users. The electricity levy represents a large share of the total cost of electricity for small consumers particularly in Denmark and to some extent in Sweden.

The VAT is a percentage of the electricity price. Thus, VAT enhances price signals from both grid tariffs and electricity prices and probably does not distort incentives for demand response. Levies, on the other hand, are fixed fees per kWh of electricity used and thereby mutes the price signal. It is however uncertain to what extent taxes and levies actually affect the efficiency of demand response.

On the other hand, it is impossible to design a tax system that is perfectly efficient and does not have any adverse effects. Moreover, levies are imposed with other purposes than promoting demand response. The structure of the levy should thus reflect the basis of the levy, and not how it affects the volumes of demand response to price signals. But levies can still be designed in different ways. When designing levies and other measures, one should try to limit the possible negative effect that taxes and levies may have on the efficiency of price signals. For example, a reduction of taxes and levies during high price periods is proposed from time to time. Such intervention would however counteract price signals, reduce the efficiency of price formation and disincentivize demand response in scarcity situations.

Energy authorities should provide general guidance on how the impact on demand and demand response should be taken into account in the design of measures affecting energy use, with a view to reducing unnecessary adverse effects.

5.2.2 Wholesale price regulations and bidding restrictions

All measures to improve the short-term price formation in the market are beneficial in terms of reducing overall system costs and providing more efficient long-term investment signals. The Nordic wholesale market is generally perceived to be highly efficient and well-functioning. However, there are some indications that there is still room for improvement. For example, in Denmark, they observe that the decentral combined heat and power plants are not very active in the market, although calculations indicate that it would be profitable for them. Energinet.dk is currently carrying out a project to assess the possibility of increased participation of these actors.

Price cap

Mainly for technical reasons, a price cap is implemented in the Nordic Elspot wholesale market algorithm. The official minimum and maximum prices are set at -500 and 3,000 EUR/MWh, respectively, corresponding to -6,500 and 39,000 SEK/MWh. These prices are rarely achieved, except in situations where it is impossible to equate supply and demand based on market bids (cf. section 3.2). As we have seen above (cf. section 4.3), a substantial potential for demand response has been estimated for prices up to 13,000 SEK/MWh.

Hence, the price cap does not seem to be a barrier for demand response in the market.

Bidding rules for the peak load reserves

Elspot prices do not necessarily reach the maximum price level even if equilibrium is not found. The reason for this is the rules for activation of the Finnish and Swedish peak load reserves. The basic rule is that the peak load reserve is bid into the market at a price 0.1 EUR/MWh above the highest commercial bid in the market.[29] The purpose of the rule is to minimize the impact of the PLR on Elspot price formation. Ideally, this price rule would incentivize all other market bids up to the price cap. For example, if the PLR would always be bid according to marginal costs with a given mark-up (as previously), this price level could constitute an effective price cap in the market.

Historical evidence does however indicate that the demand side in the market is slow to react to high prices. If the peak load reserve is relatively cheap – according to the pricing rules – the existence of the PLR may act as a barrier for investments or efforts to increase demand response in the market. If the demand side needs some early "shocks" in order to start submitting flexible bids in the spot market, the pricing rule for the PLR may mute the eagerness to act. The demand side may be reluctant to place high bids in Elspot, it the PLR pricing rule ensures that scarcity prices are reasonable.

[29] The highest commercial bid is defined as the highest bid with a volume change (increased sale or reduced purchase). The bid can be higher if activation costs for the peak load reserve are higher (minimum bid). The reserves can only be activated if the market fails to equate supply and demand in Finland and/or Sweden.

Hence, as long as the PLR is present in the market, it may affect long-term price formation and capacity adequacy in the market.

Grid operation and ATC values

Operation of the grid may affect market prices. It is therefore important that the TSOs follow clear and transparent rules for grid operation. The TSOs calculate Available Transmission Capacities (ATC) for the interconnectors between bidding areas 2.5 hours prior to gate closure in Elspot. The calculation is based on expected consumption and flows. The calculation of ATC values should be based on clear and transparent criteria, e.g. the n-1 criterion. If, for example, the TSOs transgress the n-1 criterion in the calculation of ATC values in cases where the capacity margin is expected to be tight, it has a price effect in the Elspot market: The price in the deficit area will lower, and the price in the surplus area higher. Hence, this practice may constitute a (soft) price ceiling and undermine the profitability of investments in demand response and capacity expansions in the deficit area.

This is not to say that flexibility in grid operation should not be used to handle scarcity situations, but it is important that this is done in a way that distorts market signals as little as possible (cf. also the rules for activation of the peak load reserve). In such cases, grid measures should rather be applied after gate closure in the Elspot market, e.g. by making more capacity available for intraday trade or exchange of reserves.

NordREG (2010) points out that in the current market design, TSOs announce ATC values to the market 2.5 hours before gate closure in Elspot. Hence, ATCs are based on expectations rather than actual consumption and generation. NordREG also notes that during the price peak of January 8, 2010, an overestimation of consumption in the Oslo region may have resulted in lower than necessary ATC values. Implicitly, the scarcity could have been reduced or avoided had ATC values been set higher, or consumption been estimated more accurately.[30]

A study by Gaia Consulting concluded that the TSOs may not have the proper incentives to set optimal ATC values (NordREG, 2011). NordREG (2014) reports that NordREG concluded that the current method works sufficiently, although there is room for improvements in some areas.

The rules for activation of the peak load reserves in Finland and Sweden imply that possible grid measures should not be exploited before all market

[30] On January 8, 2010, the Elspot capacity on the Hasle connection was set to zero, whereas the normal capacity is 2,000 MW.

options are used, including activation of the peak load reserves. This appears to be a sound mechanism in terms of transparency and clear work distribution between the market and system operation responsibilities.

Hence, we do not say that grid measures should not play a role, but the timing of grid measures matter for the market prices. Hence, the rules for ATC calculation should be clear and transparent, and not subject to TSO discretion. However, if it turns out that more capacity may be utilized to balance, the system, such opportunities should be exploited by e.g. offering the capacity in the intraday market or for exchange of reserves.

Implementation of flow-based market coupling could potentially contribute to improved utilization of the grid and more transparent calculation of grid capacities.

Congestion management: Bidding zones and redispatch

Similarly, redispatching instead of finer bidding zone delimitation mutes price signals to market participants who do not participate in the redispatching. For example, the division of Sweden into several bidding zones seems to be a good example of a market design reform that has reduced system costs and is likely to improve investment signals as well. Reducing the magnitude of redispatching implies that congestions that are currently bidding zone "internal" will be reflected in spot market prices.

As mentioned above, flow-based market coupling combined with proper bidding zone delimitation should increase the efficiency of price formation in the Nordic market as well as on the continent. Ideally, flow-based market coupling is equivalent to nodal pricing if all nodes of the grid are represented in the algorithm. In practice, however, one must probably chose a reasonable level of detail in order to make the solution calculable on a daily basis, which implies a cruder representation of the grid.

Flow-based market coupling should cater for improved efficiency of grid utilization, as flows can be based on actual bids instead of predictions made prior to day-ahead bidding, i.e. ATC values can be calculated as part of the market algorithm. As part of the implementation of flow-based market coupling, a finer bidding zone delimitation should be considered.

It should be noted that increasing the number of bidding zones does not necessarily increase the number of price areas or price differences in the market (cf. Bye *et al.*, 2010). The main benefit of increased bidding zones is to improve the efficiency of price formation in the market. Some fear that a larger number of bidding zones may reduce the hedging opportunities in the market. However, if zonal (or nodal) prices are highly correlated with the system price, low liquidity in zonal (or nodal) hedging products is not necessarily a strong argument against finer bidding zone resolutions.

Since demand response and demand side flexibility is likely to play an increasing role in the balancing of the power system, it is however, also important that the locational price signals are passed through to end-users. Some trade-offs should be observed. If end-users do not have the opportunity, or if it is prohibitively costly, to respond to locational price signals, complex pricing schemes may merely increase transaction costs. However, it is difficult to estimate the willingness to pay for new generation and transmission capacity without exposing end-users to efficiently differentiated price signals. Although end-users are not prone to respond in the short term, prices may play a role for investments that affect long-term demand, energy efficiency, and flexibility. Including also development of new devices and services for efficient demand response and demand side management.

Time resolution: 15 minute bids

The current time resolution in the spot markets is one hour. As we have noted in chapter 5, the variations in flows in the future system are likely to increase due to increased trade and increased intermittent generation capacity. Changes in demand patterns may also imply that variations in demand increases. Increased flow variations in the grid may imply increased balancing costs. Applying a finer time resolution may hence reduce the imbalances and the TSOs need for reserves. We note that the changes in flows will not be reduced, but structural imbalances will move from the reserve markets to the day-ahead and intraday markets. Such a change in the market design would make balancing cheaper due to longer planning horizons and cater for mobilization of more flexible resources than the current hourly time resolution. In addition, the BRPs would be responsible for a larger share of the (structural) imbalances.

The cost of using flexibility in the day-ahead and intraday markets is in general less than applying it for balancing purposes in the real-time markets. Thus, limiting real-time imbalances by moving a larger share of imbalances to an efficient day-ahead and intraday market is an attractive measure.

Nordic spot price formation is already market based and highly efficient compared to most other power markets. An assessment of shorter time resolution and market closure closer to the operating hour in the Nordic market is recommended by TemaNord (2014), as this may potentially influence the demand for and cost of balancing services.

Connect et al. (2014) also recommend that 15-minute products are introduced in the day-ahead market in order to reduce the need for counter trades and balancing reserves. They do however also recommend that the 15-minute products are combined with 1 hour block contracts.

We recommend that 15-minute time resolution is pursued even for the Nordic market. The details need to be assessed more closely, however. Notably, the compatibility with metering of consumption should be addressed.

5.2.3 Ineffective intraday, balancing and ancillary services' markets

The design of intraday, balancing and ancillary services' markets matter for capacity adequacy as well. The market design and relation between different markets and mechanisms are explained in section 3.1. The Nordic day-ahead market is considered both highly efficient and liquid. Trade in the intraday market is however quite thin.

Balance responsibility

The agents in the power system must notify the system operator of their planned generation or consumption before the operation hour, cf. section 3.1.

The prices and costs for imbalances are different for generators and consumers. Moreover, the cost depends on the system imbalance. In the following example, based on Bye *et al.* (2010), we assume that the Elspot price is 400, the tertiary reserve price for up-regulation is 420 and the tertiary reserve price for down-regulation is 380.

Table 17. Examples of imbalance costs and payments

System	Tertiary reserve price	Generator / consumer balance	Cost or payment	Generator Cost / Payment	Consumer Cost / Payment
Deficit	420	Helps	Payment	400	420
Deficit	420	Burdens	Cost	420	420
Surplus	380	Helps	Payment	400	380
Surplus	380	Burdens	Cost	380	380

Source: Bye *et al.* (2010).

We note that the imbalance costs differ between generators and consumers when their imbalances help the system. Then the imbalance payment for generators is lower in the case of system deficit, and the payment is higher in the case of system surplus. The intention for this so-called two-price system is to provide a stronger incentive for producers' to avoid imbalances, thereby reducing the TSOs risk of not being able to balance the system. Providing the generators with stronger incentives to be in balance should also increase the incentive to handle imbalances in the intraday market, rather than leaving the balancing to the TSO in the operation hour.

The flipside of stronger incentives for generation to be in balance is however that incentives for demand to be in balance may be weaker. Consider the scarcity situations experiences in the Nordic market over the last few years (cf. section 3.2). The day-ahead auction has been unable to equate supply and demand, and the peak load reserve has been activated (or tertiary reserves in Denmark). However, in the operation hour, demand has been lower than anticipated, i.e. the net demand imbalance has "helped" balance the system. This imbalance has been paid the balancing reserve price. At the same time, the overstatement of load has actually contributed to or created the problem in the first place. If on the other hand, the imbalance had been paid according to the spot price, whereas down-regulation had been awarded the balancing price, demand would have a stronger incentive to bid its actual flexibility in the day-ahead, intraday and reserve markets. In a shortage situation, if demand had bid its "actual" demand curve (reflecting its willingness to reduce demand) in the day-ahead auction, the market would probably have reached equilibrium, and it would not have been necessary to activate the peak load reserve in Finland and Sweden.

Hence, the design of imbalance payments appears to be unfortunate for two reasons:

1. It may bias the demand side towards overestimating consumption in scarcity situations.
2. The demand side does not have to actively bid flexibility in Elspot and Elbas, or in the reserve market in order to receive the tertiary reserve price.

As noted by NordREG (2011): "The workshop pointed out that there was substantial demand response in the Nordic electricity market during the peak hours, but that most of the demand response happened in response to peak prices, not as a part of the Elspot trade. In order to affect peak prices, it is important that incentives are created so that this flexibility is bid into Elspot."

Hence, the "two-price system" may affect the day-ahead market's ability to establish equilibrium in scarcity situations, reduce trade in the intraday market, and increase the cost of balancing.

Similarly, TemaNord (2014) arrives at the following conclusion "The cost of using flexibility in the day-ahead and intraday markets is in general less than applying it for balancing purposes in the real-time markets. Thus, limiting real-time imbalances by having an efficient day-ahead and intraday market is an attractive measure."

The intraday market

Incentivizing demand flexibility by equalizing the incentive to be in balance for generators and suppliers/large consumers, should also increase the activity in the intraday market.

Price formation should reflect the price sensitivity on the demand side, in principle including also the price sensitivity of small consumers. However, most consumers cannot participate directly in the market due to e.g. size requirements (see also section on reserve markets below). However, groups of consumers may be represented in the market by so-called aggregators. Currently, all balance responsible parties may in principle act as aggregators for consumers who are too small to participate directly in the market, or find the costs prohibitive. Some has suggested that aggregators are exempt from the balance responsibility in order to increase the participation of demand response in the markets. However, such a move is likely to increase the imbalances, and hence, the balancing costs. Hence, even independent service providers (aggregators) should be required to be balance responsible parties.[31]

All measures to increase efficient settlement of the spot prices, as described above, serve to limit the imbalances occurring after gate closure, and may thus reduce the need for balancing resources. If the spot market design is changed, the implications for the demand for balancing should be evaluated. Making the spot markets work as efficiently as possible is thus crucial for balancing markets as well.

Ancillary services

Ancillary services may either be provided as requirements for market participants, or be acquired through market-based mechanisms. Hence, provision of ancillary services may represent an additional cost to some market participants, if the provision is required without any or proper remuneration, and it may represent an additional revenue source to some, if provision is procured through market mechanisms. Efficient procurement of ancillary services may hence reduce system costs and signal the system needs via market prices. For example, Connect *et al.* (2014) argue that the required provision of reactive power by conventional plants unnecessarily increases the minimum generation of power plants (must-run). They recommend that reactive power should be increasingly provided independently from power plants.

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[31] See for example THEMA (2012) for a discussion of barriers and the role of aggregators in the market.

The requirements for generators and other market participants will be regulated by the network codes. The connection codes regulate the connection of generation and demand to the grid. There are three Connection codes; Requirements for Generators, Demand Connection Code and HVDC Connection Code. These Network Codes define the roles and the relationship between TSOs and generators/consumers/DSOs and set the minimum criteria for connections. The requirements relate to the size and impact of the units connected to the grid, whereas stricter requirements apply to units that have bigger impact on the network and on cross-border power exchange.

To the extent that the network codes make room for it, we recommend that the Nordic TSOs and regulators assess the requirements and remuneration for ancillary services in the Nordic market in order to assess the scope for increased efficiency. We do not have any basis to assess the existence or extent of such efficiency gains in the Nordic area. We would also like to emphasize that potential efficiency gains should be weighed against increases in transaction and administrative costs.

Reserve markets

Reserve markets can be improved by increased integration among the Nordic countries and by harmonizing product definitions across borders. Should balancing markets not be further integrated, product definitions should be reconsidered in each country. Reduced bidding sizes, the duration of load adjustments, response times, and intervals between disconnections are (non-exhaustive) examples of product characteristic that should be assessed.

In Sweden, demand side bids come mainly from the pulp and paper industry, and the TSO is working to increase the participation of demand side resources in the reserve markets. Possible measures include:

- Information (fact sheets) and help to get started.
- Reduced minimum bidding volume. In SE4 (southern Sweden) the minimum bidding size has already been reduced from 10 MW to 5 MW. This has increased bids in SE4 somewhat, but volumes are still limited. A general reduction from 10 to 5 MW is currently tested.
- Make it possible for providers to specify resting time between activation periods.
- Simplify the bidding process, e.g. annual bids.
- Increased automation of activation of responses.

Fingrid also focuses on stimulating demand response in the market, including for operating reserves. Currently, 400 MW of the operating reserve is from loads. Moreover, consumers on market contracts are not billed according to standard profiles any more. Fingrid assumes that the potential for demand response from end-users is much higher than what is currently offered.

The implementation of the RKOM market in Norway and the introduction of the "limited" product is another example of changes in the market design that could accommodate flexible resources with other characteristics than conventional generation capacities, and which may provide valuable services to the system.

TemaNord (2014) recommends that the Nordic regulators consider the following measures specifically aimed at improving the reserve markets:

- Assess how products should be designed to increase the participation of generators and consumers (the bid size, duration, recovery time and response time).
- Assess the costs and benefits of extending the mandatory implementation of autonomous operation to facilitate system frequency control for consumers both at TSO and DSO level.
- Work closely together with TSOs to assess and implement improved market design for balancing. If a Nordic cooperation is not established, the national regulator and TSO should continue this work on a national level.

Balancing reserve prices vary considerably between market areas. Ideally, interconnector capacity should be utilized for exchange of the products with the higher value (price difference between areas). The "Hasle pilot", carried out from week 44–51 in 2014, tested the effect of reservation of interconnector capacity between Norway and Sweden for exchange of secondary reserves if this is deemed more profitable than Elspot exchange. The pilot project is currently being evaluated. The provision of automatic reserves from Norway to Denmark on the SK4 cable is another example of reservation and exchange of reserves across interconnectors.

Fingrid is currently importing regulating reserves from Norway and Sweden subject to available transmission capacity, but the scope is reduced as the value of Elspot exchange increases (and the interconnector capacity utilization). In order to reserve interconnector capacity for balancing reserves, welfare economic gains must be demonstrated (according to European legislation). So far, calculations do not reveal such gains.

Developing solutions for efficient exchange of balancing resources can potentially reduce the cost of balancing, and at the same time increase the value of the most efficient balancing resources. In order to accomplish this, it may be desirable to reserve interconnector capacity for exchange of balancing resources. Although it may not be welfare enhancing to reserve capacity with the current prices and market conditions, rules and regulations should be developed and put in place, in order to prepare for the future.

5.2.4 Market concentration

As far as we can discern, there is no reason to assume that market concentration is or will be a cause of of capacity adequacy challenges in the Nordic market. The market is widely perceived to be highly liquid and efficient.

Analyses of the cases with capacity shortages in the Elspot market, do not point to market concentration as a concern.

That being said, such concerns could of course appear in the future. Increased demand flexibility would in any case help mitigate market power on the generators' side.

5.2.5 Ill-designed renewable support mechanisms

Renewable support mechanisms may undermine the profitability of other investments in three ways:

- Reduced average price level.
- Increased number and magnitude of negative prices.
- Increased system costs.

The impact on the average price level is basically a consequence of subsidies to renewable capacity, and not *per se* a design issue. However, design choices affect the extent to which subsidies reduce average prices as well.

Connect *et al.* (2014), in a study of German market design, finds that in the past, fixed feed-in tariffs led to an inflexible supply of RES-E that was decoupled from the power prices signal. In consequence, prices sank to an unnecessary low level in situations with high feed-in and simultaneously low demand (in Germany).

Generally, subsidy schemes are less efficient the less the subsidy reflects the market value of generation. As such, investment subsidies are less prone to affect the short-term market price signals. Production subsidy schemes imply that for example wind power generation is paid even when prices are negative. If for example the production subsidy is 10 EUR/MWh, a wind power producer will make revenues as long as the price is above -10 EUR/MWh. Fixed feed-in tariffs or feed-in premiums may be just as bad as a general priority provision for renewable generation in the grid. If however, the support is not provided for a certain period, but for a number of full-load hours, or is not provided for hours in which the electricity price is negative, such adverse effects on market prices are avoided (as for example in the Danish support scheme for offshore windmills).

The Finnish feed-in tariff is variable up to a maximum, and depends on market prices. The feed-in tariff is calculated as the difference between a target price and the 3-month average market price. The maximum feed-in tariff of 53.5 EUR/MWh is paid when the average market price is equal to or lower than 30 EUR/MWh, i.e. the average per MWh revenue of the RES generator is equal to the target price as long as the market price is lower than the target price and higher than 30 EUR/MWh. If the (average) market price is lower than 30 EUR/MWh, the per MWh revenue is lower than the target price. Moreover, the generators are not entitled to the feed-in tariff for generation in hours with negative (local) market prices. Hence, RES generators do not have an incentive to generate when market prices are negative.

The Swedish-Norwegian Elcertificate market constitutes a market-based production subsidy scheme, i.e. Elcertificate eligible generation has an incentive to produce even if prices are negative (down to the Elcertificate price). As long as the likelihood of negative prices is much smaller than in thermal systems on the continent, including in Denmark, the weaknesses of the subsidy scheme designs in Finland, Norway and Sweden do not necessarily represent a serious problem for investments. However, in extreme years, and depending on the market development, negative prices may become more likely in the future.

The extent of the negative impact of ill-designed support mechanisms varies between technologies. Hydropower with high flexibility is less affected by negative prices than nuclear power and gas and coal plants. Hydropower may easily avoid generation in hours with very low or negative prices, whereas the higher the start-up costs, the more are thermal power stations willing to pay (in terms of negative prices) to avoid them. But even existing run-of-river hydropower plants are likely to be negatively affected by negative prices as their generation is not flexible.

Balancing costs also affects the generation and bidding of renewable energy. In some countries renewable electricity capacity are not properly charged for balancing costs, which may increase the system cost burden on other types of capacity. As far as we know, renewable generation in the Nordic countries is generally balance responsible, with a possible exception for distributed generation.

As the current design of the Elcertificate market, and the feed-in tariffs in Finland and Denmark (except offshore wind) is not ideal, the Nordic countries should assess to what extent the design should be changed in order to mitigate adverse effects on capacity adequacy, i.e. the profitability of conventional generation. In any case, when future RES support schemes are to be designed, such adverse market effects should be clearly addressed.

5.2.6 Support schemes for fossil and nuclear generation

We have not identified any support schemes for fossil and nuclear generation, including refurbishment of such capacity, in the Nordic market, that represent severe market inefficiencies.

5.2.7 Other relevant regulatory aspects

Grid tariffs

Grid tariffs serve two very different purposes. Efficient tariffs reflect the marginal (variable) cost that each customer or user imposes on the grid. Variable tariff elements typically reflect marginal losses, and individual connection and administrative costs. However, due to the cost structure in the grid, revenues from marginal tariffs do not cover total grid costs. Hence, additional tariffs are needed to cover residual costs. Whereas marginal tariffs are designed in order to convey efficient price signals, residual tariffs should be designed as neutral as possible, i.e. efficient residual tariffs should *not* affect investment, generation or demand decisions. To the extent that it is desirable to take distributional effects into account by differentiating the residual tariffs, the differentiation should as far as possible also be neutral.

However, grid tariffs should be designed to promote efficient operation and development of the grid, and not to induce demand response in general. On the other hand, as grid tariffs may be designed in different ways, one should be careful not to distort price signals from the market, i.e. grid tariffs which unnecessary mute or counteract market price signals should be avoided.

The G component in grid tariffs

Capacity adequacy depends on investments in (reliable) generation capacity, energy efficiency measures and flexible demand. Our calculations indicate that investments in pure peak load units are unlikely to be profitable in the Nordic market in the 2030 horizon. However, there is a large potential for expansion of the effect capacity in hydropower. For example, in its latest report on costs in the power sector, the Norwegian regulator states that Norway has a significant potential for "balancing power" (NVE, 2015). The technical potential is probably "several thousand MW". The realistic potential is however uncertain and limited by physical factors, grid issues, market developments and policy decisions, such as e.g. EU's Water Framework Directive (2000/60/ec). Although the potential for increased effect capacity in the other Nordic countries is probably smaller than in Norway, we assume that similar opportunities exist, at least in Finland and Sweden.

THEMA (2015a) compares the grid tariffs for generation in the Nordic countries and the EU, focussing on the G component, i.e. the part of generators' grid tariff that is not intended to yield price signals to grid customers (the residual tariff). The report argues that energy-based tariffs based on historical generation (lump-sum tariffs) are preferable to capacity-based tariffs, particularly in power systems relying heavily on renewable energy. Such considerations constituted the basis for prior changes in the Norwegian generator tariffs in 2001 (Statnett, 2002), from a capacity based tariff to an energy based lump-sum tariff.

Table 5.4 shows the G component in grid tariffs in the Nordic countries, the Baltic states, Poland and Germany. The Nordic countries are set apart from the rest of the area by imposing residual tariffs on generators at all. Differences in the energy based G-tariff affect competition between generators in different market areas in hours when interconnectors are not congested.

ACER is also of the opinion that "there is an increasing risk that different levels of G-charges distort competition and investment decisions in the internal market".[32] In order to limit this risk, G-charges should be "cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe."

[32] Opinion of the Agency for the Cooperation of Energy Regulators No 09/2014 of 15 April 2014 on the appropriate range of transmission charges paid by electricity producers.

The Swedish G component is capacity-based and differentiated between bidding zones. THEMA (2015b) shows that the capacity charge creates distortions between generation technologies, namely by putting an excess burden on capacity with a low load factor and high regulating capability in particular, i.e. the typical characteristics of flexible capacity. The tariff is based on subscribed capacity and penalizes injections above the subscription level. This "creates incentives to underutilize generation capacity and possibly to shortages in the grid in peak load hours. Finally, economically efficient investments in pumped storage and hydropower upgrades may become unprofitable." The report also suggests that the differentiation between zones does not reflect differences in grid costs between zones. Whereas the G component in Norway is a lump-sum energy tariff in accordance with ACER's opinion, the Finnish and Danish G-tariffs are energy-based, but as far as we know, not in accordance with the ACER definition of lump-sum G-tariffs.

Table 18. Generator tariffs in selected countries, SEK

Country	G component	Comment
Sweden	22–51 øre/kW	Varies between price areas
Denmark	0.4 øre/kWh	DKK 0.3 øre/kWh. Wind power and local CHP subject to purchase obligation are exempt.
Finland	0.8 øre/kWh	0.9 EUR/MWh (2015, up from 0.7 in 2013 and 0.85 in 2014)
Norway	1.0 øre/kWh	Additional system tariff of NOK 0.2 øre/kWh and energy charges based on marginal losses and area price
Germany	0	
Poland	0	
Estonia	0	
Latvia	0	
Lithuania	0	

Source: THEMA (2015b).

In other words, capacity-based generator tariffs may disincentivize investment in capacity expansions in existing and new hydropower plants, and as such, act as a barrier to increased peak-load capacity and flexibility in the system. In the Nordic setting, the current tariffs constitute a barrier to investments in the Swedish market.

In order to increase efficiency in the integrated market, rules should be harmonized. However, if the rules are harmonized in the Nordic/Baltic area, it is important that the Swedish model is not adopted as the common model, as it increases the cost of utilizing generation capacity in peak load and inherently acts as a barrier to profitable capacity investments.

DSO regulation

TemaNord (2014) notes that the overall economic regulation of the DSOs may also be relevant for efficient utilisation of demand flexibility. The Nordic DSOs are regulated through revenue caps. Although the detailed regulations differ, revenue cap regulation should in general provide clear incentives to stimulate demand flexibility when it is a cost efficient alternative for handling of peak loads in the distribution grid. However, lessons from both theory and practice show that providing incentives for the right trade-off between grid investments and demand response is a complicated matter. Hence, it may still be worthwhile to assess the implications of the current DSO regulation for the DSOs incentives to facilitate demand response.

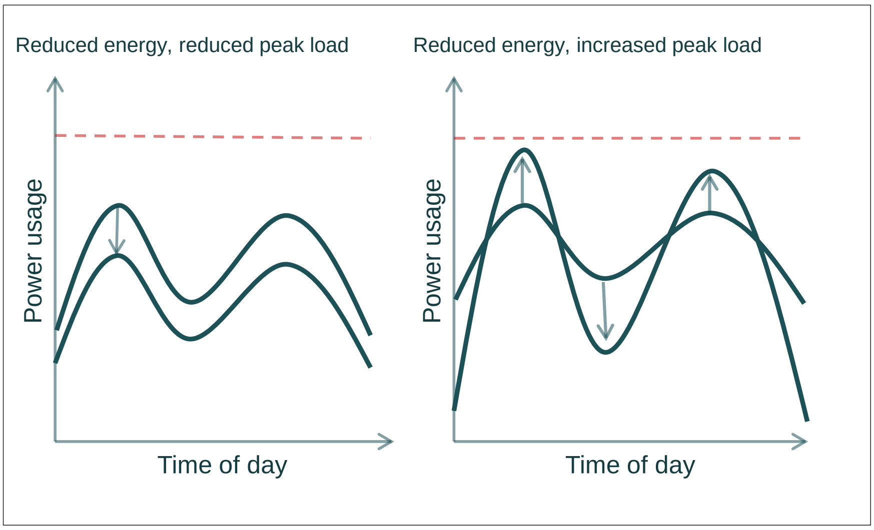
It should also be taken into account that DSOs must also consider security of supply and power quality when evaluating how grid constraints can be handled in a cost efficient way.

Energy efficiency measures

Similarly to the implementation of the RES directive and national RES targets, implementation of energy efficiency targets and policies may affect capacity adequacy in the system adversely if subsidies and incentive regulations are not carefully designed.

Often energy efficiency reduce peak demand as reduced energy levels also reduce the power used, as illustrated in the left panel of Figure 5.4. This will apply to the implementation of more energy efficient appliances in general, and often to more energy efficient buildings. For some changes on the demand side, however, there is a substantial risk that the peak load and load variations increase when electricity consumption is reduced (i.e., reduced load factor). This is illustrated in the right panel of Figure 5.4. For example, reduced night temperatures in buildings, to save energy, will increase the overall energy efficiency, but will increase the need for power to quickly increase the temperature in the morning, thereby increasing the load during morning peak. Hence, improved energy efficiency does not always improve capacity adequacy and measures to increase energy efficiency should take this into account.

Figure 30. Energy efficiency may increase or decrease the peak load



Source: TemaNord (2014).

A study of energy efficiency policies and measures in Norway (THEMA, 2014a) discusses how energy efficiency policies may affect security of supply in the electricity sector. The study finds that several of the relevant energy efficiency measures reduce heating demand, and as such, reduce the need for winter energy. However, the impact on maximum peak load and demand flexibility may vary between measures.

Company taxation

Company taxes such as the ordinary income tax, the Norwegian special tax on hydropower ("grunnrenteskatt"), and property taxes will also affect incentives for investments in generation capacity (see e.g. ECON Analyse, 2003; THEMA, 2014b; and the Ministry of Finance, 2008). While such taxes may have a significant impact in the long run, particularly between generation technologies and between the Nordic countries, we have not considered the impact of the company tax system in this report. However, we note that the relevant authorities should keep a close eye on the incentive effects of the tax system and if necessary make adjustments in order not to disincentivize economically efficient generation.

6. Summary of recommendations

Capacity adequacy is not only about the market's ability to handle shortages when shortages occur, but rather about the market's ability to ensure that capacity shortages do not occur too often, and at unacceptably high costs to consumers and the society. For the market to serve that purpose, the regulatory framework and the market design must enable the proper market dynamics. This implies making room for price signals to increase in times of shortages, and make sure that price signals reach market participants. If proper price signals do not reach market participants, the market participants cannot be expected to react adequately, be it in terms of short-term responses to shortage situations or in terms of long-term investments decisions. Thus, capacity adequacy is to a large extent about getting prices right.

Generally, we conclude that the Nordic market seems to be quite robust in terms of capacity adequacy when we take the potential contributions from surrounding markets into account, and in addition the potentials for increasing the power capacity and the contributions from demand response. However, there is substantial uncertainty about market developments and the need for capacity and flexibility in the future market. Hence, even the Nordic market should be prepared for increasing capacity challenges.

When or if, in the future, prices and price variations increase, it is important that market and regulatory barriers do not serve as barriers for profitable demand flexibility and increases in effect capacity and flexible generation. In the future, we must expect that the demand side will play an increasing role in the market. Currently, the demand side is not very active in the market, and we cannot expect demand response to materialize overnight. For example, development of smart solutions and services will need some time to develop and mature.

At the same time, demand response should only be activated if it is the most efficient measure to handle different situations in the market. There is probably a significant potential for increased investments in power capacity and flexibility in the existing hydropower stations. Barriers for exploitation of this potential should be removed.

The main conclusions on the adequacy of the current market and regulatory framework can be summarized as follows:

1. Retail prices
   - Fixed price contracts are not a barrier to demand response. Any unnecessary obstacles for flexible contracts should however be removed.
   - Taxes and levies should be designed so as to not mute the price signals from the market.
   - Energy authorities should provide general guidance on how the impact on electricity demand and demand response should be taken into account in the design of taxes and levies affecting electricity demand.
2. Wholesale prices
   - The price cap in the market does not seem to constitute a barrier.
   - The bidding rules for the peak load reserves may reduce the incentive for demand response in the Elspot market, and may affect short- and long-term price formation.
   - TSOs should follow clear and transparent rules for grid operation, including calculation of ATC values.
   - Grid measures to handle capacity shortage in Elspot should be applied after gate closure.
   - Bidding zones should be defined according to congestions and the magnitude of redispatching reduced in order to strengthen locational price signals.
   - Flow-based market coupling should be implemented, in combination with a finer bidding zone resolution.
   - Time resolution in Elspot and Elbas should be considered shortened from one hour to 15 minutes in order to reduce balancing costs and increase the incentive to handle imbalances in the spot markets.
3. Intraday, balancing and ancillary markets
   - The two-price system for imbalance settlement should be reviewed, in particular the impact of the weaker incentives for demand to be in balance.

- The possibilities for demand to participate in the intraday market via aggregators should be assessed. However, all market participants should be balance responsible in order to reduce the cost of imbalances.
- TSOs and regulators should assess the requirements and remuneration for ancillary services in order to assess the scope for improved efficiency and cost-recovery.
- Reserve markets should be integrated and products harmonized.
- Product definitions should be reviewed in terms of barriers to demand side participation.
- The possibility of reserving interconnector capacity for exchange of balancing resources, when efficient, should be pursued.

4. Renewable support schemes
   - Feed-in tariffs and Elcertificates may have adverse market effects. The Nordic countries should consider changing the support schemes for renewable generation after 2020.
5. Other regulatory aspects
   - Grid tariffs should be designed to convey efficient price signals of grid costs, and to not mute or mitigate price signals from the market.
   - The G components should be harmonized and designed in accordance with ACERs definition of lump-sum tariffs.
   - The implications of the current DSO regulation on the incentives to facilitate demand response should be reviewed.
   - The design of energy efficiency measures should take impacts on peak load and demand flexibility into account.
   - Relevant authorities should consider the incentive effects of the tax system when it comes to impacts on economically efficient generation investments.

We identify a number of options for improving the market design and regulatory framework in the Nord Pool market area. This study cannot conclude firmly on all accounts, but the following suggestions should be considered:

Short-term measures: Concrete measures in the short term include removal of barriers to investments in peak and flexible capacity in the grid tariffs, set clear rules for the TSOs calculation of interconnector capacity made available to the market, and make sure that the imbalance settlement yields equal incentives for generation and demand to be in balance. The pricing of Elspot activation of the peak load reserve in Finland and Sweden should be reviewed, to assess whether it constitutes a barrier to demand flexibility in the market. Moreover, the adequacy of the remuneration for system services should be assessed, and whether product definitions should be revised in order to facilitate valuable contributions from the demand side. Finally, general guidelines for how different authorities should consider system and capacity adequacy effects (including flexibility) in the design of policy measures and regulations that affect electricity supply and demand. This is for example relevant when energy efficiency measures in different sectors are designed.

Medium-term measures: It is important to facilitate efficient exchange of reserves between the countries through harmonization of product definitions and development of models for efficient allocation of interconnector capacity between exchange in Elspot and reserve markets. This should increase the value of flexible resources. Flow-based market coupling, 15-minute time resolution and the bidding zone delimitation could strengthen Elspot market signals and increase trade in Elbas. Hence, the future market design should be developed with these considerations in mind. The countries in the Nord Pool areas do not have a common framework for capacity adequacy assessment. Such a common framework should be developed.

Long-term measures: Flow-based market coupling, possibly in combination with new bidding zone delimitation and 15-minute time resolution, should probably be implemented. The design should be based on a thorough assessment of the design elements. Most countries will probably support renewable generation even after 2020. Thus, it is important to make sure that the support schemes are designed in a way that does not yield adverse price effects and increased system costs.

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Sammendrag på norsk

Det skjer store endringer i det europeiske kraftmarkedet, både når det gjelder sammensetningen av produksjonskapasiteten og når det gjelder markedsdesign og -integrasjon. Disse endringene påvirker også det nordiske markedet. Økningen i uregelmessig fornybar produksjon og redusert lønnsomhet for konvensjonelle kraftverk har ført til en økende bekymring for forsyningssikkerheten. De nordiske og baltiske landene er tett integrert (Nord Pool-området). Forsyningssikkerheten i dette området bør derfor behandles samlet og ikke for hvert land for seg.

Problemstilling og metode
Tema for denne rapporten er:

> Hvilke markedsløsninger kan man bruke for å sikre forsyningssikkerheten i Nord Pool-området, og hvordan kan man innføre disse markedsløsningene på en effektiv måte?

Vi definerer tilstrekkelig forsyningssikkerhet som systemets evne til å etablere likevekt i spot-markedet, og samtidig tilby tilstrekkelige balanseressurser i driftstimen, selv i ekstreme situasjoner.

Det betyr at en vurdering av systemet må omfatte både prisdannelsen i Elspot og den løpende fysiske balansen i systemet. Et velfungerende markedsdesign – fra forward-markedene til reservemarkedet – er det viktigste grunnlaget for langsiktig forsyningssikkerhet.

Analysen fokuserer på utviklingen mot 2030. I et system med mye variabel og uregelmessig produksjonskapasitet og stor utvekslingskapasitet, er det ikke bare kapasitet til å dekke forbruket på de kaldeste vinterdagene (topplast) som avgjør forsyningssikkerheten. I tillegg må systemet kunne respondere på raske endringer i flyten i nettet og i vind- og solkraftproduksjon, og det må være mulig å skaffe til veie tilstrekkelig energi når vind- og solproduksjonen er lav over lengre perioder. Forbrukernes evne og mulighet til å bidra til forsyningssikkerheten blir også viktigere.

Analysen følger i stor grad veilederen for vurdering av kapasitetssituasjonen som EU-kommisjonen har utarbeidet i forbindelse med at flere land har innført, eller planlegger å innføre, kapasitetsmekanismer.

Det var imidlertid ikke en del av oppdraget i dette prosjektet å vurdere innføring av kapasitetsmekanismer i det nordiske markedet.

I tråd med veiledningen fra EU-kommisjonen, har vi gjennomført en analyse i tre trinn:

- En modellbasert analyse for å identifisere og karakterisere eventuelle utfordringer
- En vurdering av hvordan markedet bidrar til å håndtere utfordrende situasjoner gjennom handel, tilbud og etterspørsel, inkludert stimuli for økt produksjonskapasitet, forbruksfleksibilitet og utveksling
- En vurdering av om svakheter i markedsdesign og reguleringer utgjør barrierer for langsiktig forsyningssikkerhet

Vi har lagt vekten på de to siste punktene. Modellanalysen er forenklet og må tolkes med forsiktighet. Vi vil imidlertid understreke at selv en mer omfattende og grundig modellanalyse ikke bør brukes som det eneste grunnlaget for å vurdere framtidig forsyningssikkerhet. Modeller fanger ikke opp alle relevante aspekter. I tillegg finnes det ikke tilstrekkelige erfaringsdata, verken når det gjelder forbruksfleksibilitet eller hvordan tilbudssiden responderer på endringer i markedsdesign og reguleringer.

Konklusjoner

Modellanalysen indikerer ikke omfattende utfordringer for forsyningssikkerheten i Nord Pool-området fram mot 2030. Grunner til det er tilgangen til fleksibel vannkraft og betydelig utvekslingskapasitet med en rekke andre markeder, fra Russland i øst til Storbritannia i vest. I den grad utfordringer oppstår, er disse tilsynelatende først og fremst knyttet til å dekke topplasten i kalde vintre når det skjer utfall både i kjernekraften og på utenlandskablene. Sannsynligheten for at slike situasjoner oppstår, er antagelig svært liten.

Det betyr imidlertid ikke at det ikke er rom for å forbedre markedsdesign og reguleringer for å øke effektiviteten og styrke forsyningssikkerheten i Nord Pool-området.

I fremtidens kraftsystem vil verdien av effekt og verdien av fleksibilitet øke. Overordnet er det viktig å sikre at prissignalene er adekvate i alle deler av markedet. Det innebærer at prisene må reflektere knapphetssituasjoner, at fleksibilitet må premieres ut fra sin verdi, og at leveranser av reserver og systemtjenester får betaling på markedsmessig grunnlag.

I første omgang er eksisterende vannkraft antagelig den billigste kilden til økt effekt og økt fleksibilitet. Det er derfor spesielt viktig å fjerne barrierer for utnyttelse av og investeringer i effektkapasitet og fleksibilitet. Vi har identifisert flere slike barrierer. Eksempler er TSOenes praksis med å øke overføringskapasiteten til markedet ved å gjøre tiltak i nettet før handelen starter i Elspot, og utformingen av den svenske innmatingstariffen (effektavgiften).

På lengre sikt er det viktig å involvere etterspørselssiden i balanseringen av systemet i større grad. Analyser tyder på et betydelig, om enn usikkert, potensial for forbruksfleksibilitet, og ny teknologi, nye reguleringer og utvikling av nye tjenester bidrar til at det blir lettere å utnytte potensialet. Selv om prisene nå er lave og prisforskjellene små, bør man begynne å fjerne barrierer for etterspørselsrespons. Erfaringer tyder på at det tar tid før etterspørselssiden begynner å respondere på prissignaler. Eksempler på barrierer for forbruksrespons er toprismodellen i balanseavregningen og prissettingen ved bruk av effektreserven i Finland og Sverige.

Anbefalinger

Det nordiske markedet er velfungerende og modent, og det er ikke grunnlag for å gjøre store, gjennomgripende endringer i markedsdesign og reguleringer. Vi anbefaler snarere en meny av justeringer som til sammen kan styrke forsyningssikkerheten på lang sikt.

Konkrete tiltak som kan gjøres på *kort sikt* er å fjerne barrierer for investeringer i effektkapasitet og fleksibilitet i nettariffene, sette klare rammer for TSOenes beregning av overføringskapasitet og sørge for at balanseavregningen gir produksjon og forbruk like incentiver til å være i balanse i driftstimen. Det bør vurderes om den prisen som settes for aktivering av effektreserven i Finland og Sverige i Elspot, motvirker forbruksfleksibilitet, og om praksisen bør endres. Videre bør man vurdere om betalingen for systemtjenester gir adekvat kompensasjon til leverandørene, og om produktdefinisjonene i markedene for reserver og systemtjenester kan endres slik at det legges bedre til rette for at forbruket kan gi verdifulle bidrag til balanseringen av systemet. Endelig bør det utvikles generelle veiledere for hvordan ulike myndigheter skal ta hensyn til konsekvenser for forsyningssikkerhet (og fleksibilitet) når man skal utforme virkemidler og reguleringer som påvirker kraftproduksjon og -forbruk. Det er f.eks. aktuelt i forbindelse med tiltak for energieffektivisering i ulike sektorer.

På *mellomlang sikt* er det viktig å legge til rette for effektiv utveksling av reserver mellom landene gjennom harmonisering av produktdefinisjoner og utvikling av modeller for effektiv fordeling av utvekslingskapasitet mellom spotmarkedet og reservemarkedet. Det kan øke lønnsomheten av å tilby fleksible ressurser. Det bør også utredes om og hvordan flytbasert markedskobling, 15-minuttersinndeling og budområdeinndeling kan utformes for å styrke prissignalene i Elspot og øke handelen i Elbas. Landene i Nord Pool-området bør også definere en felles ramme for vurdering av forsyningssikkerheten. Det mangler i dag.

På *lang sikt* bør flytbasert markedskobling, eventuelt i kombinasjon med ny områdeinndeling og overgang til 15-minuttersinndeling, antagelig innføres, basert på en nærmere utredning av hvordan dette bør utformes. Flere av landene i Nord Pool-området vil trolig fortsatt støtte utbygging av fornybar energi etter 2020. Da er det viktig å sikre at støtteordninger blir utformet på en måte som ikke gir uheldige prisvirkninger i markedet, og som ikke øker systemkostnadene unødig.

Appendix 1: EC Checklist

Checklist for intervention to ensure generation adequacy – justification of intervention

Assessment of generation gap

1) Is the capacity gap clearly identified and does this distinguish between need for flexible capacity at all times of year and requirements at seasonal peaks? Has a clearly justified value of lost load been used to estimate the cost of supply interruptions?
2) Has the assessment appropriately included the expected impact of EU energy and climate policies on electricity infrastructure, supply and demand?
3) Does the security of supply and generation adequacy assessment take the internal electricity market into account; is it consistent with the ENTSO-E methodology and the existing and forecasted interconnector capacity?
4) Does the assessment explain interactions with assessments in neighbouring Member States and has it been coordinated with them?
5) Does the assessment include reliable data on wind and solar, including in neighbouring systems, and analyse the amount as well as the quality of generation capacity needed to back up those variable sources of generation in the system?
6) Is the potential for demand side management and a realistic time horizon for it to materialize integrated into the analysis?
7) Does the assessment base the assessment of generation plant retirements on projected economic condition, electricity market outcomes and the operating costs of that generation plant?
8) Has the assessment been consulted on widely with all stakeholders, including system users?

Causes of generation adequacy concerns

1) Has retail price regulation (with the exception of social prices for vulnerable customers) been removed?
2) Have wholesale price regulation and bidding restrictions been removed?
3) Have renewable support mechanisms been reviewed in line with the Guidance on renewable support before intervening on generation adequacy grounds?
4) Has the impact of existing support schemes for fossil and nuclear generation on incentives for investments in additional generation capacity been assessed?
5) Are effective intraday, balancing and ancillary services' markets put in place and are any remaining obstacles, in those market removed? Have any implicit price caps from the operation of balancing markets been removed?
6) Have structural solutions been undertaken to address problems of market concentration?

Options other than support for capacity

1) Have the necessary steps been taken to unlock the potential of demand side response, in particular has Article 15(8) of Directive 2012/27/EU on Energy Efficiency been implemented and do smart meter roll out plans include the full benefit of demand side participation in terms of generation adequacy?
2) Have the benefits of expanded interconnection capacity been expanded, in particular towards neighbouring countries with surplus electricity generation or a complementary energy mix been fully taken into account?
3) Have the impacts of the intervention on the achievement of adopted climate and energy targets been assessed holistically, and is lock-in of high carbon generation capacity and stranded investments avoided?

Appendix 2: The The-MA power market model

The-MA – An Advanced Power Market Model for North-West Europe

The-MA is a newly developed advanced power market simulations model developed by THEMA Consulting Group. The people behind the model have a long track record in modeling and model development. The-MA has proven its worthiness in a wide range of applications from price forecasts to scenario and interconnector analysis, for client such as OED, MD, Statnett and many more.

Main features

Hourly time resolution: The model simulates all hours of a year. This is a very important feature in order to capture price volatility in different markets. Despite the fact that prices in Norway are rather flat, due to interconnection with thermal systems, hourly resolution is also extremely important for Norwegian prices and the determination of trade and water values.

Detailed representation of hydro capacities in Norway: Other models often aggregate Nordic reservoirs into larger super-reservoirs. This approach overestimates the flexibility in the hydro system, and the aggregated reservoir inherits the slack of the large reservoirs that are combined with smaller reservoirs. The-MA uses implicit water values, simulating more than 75 reservoirs individually in order to address the constraints in a hydro system.

Detailed representation on thermal units: Thermal generation modeling includes start-up costs, part-load efficiencies and minimum stable load. Larger thermal units are modeled individually rather than in groups of plants. This also increases the transparency of the capacity assumptions significantly.

Accounting for volatility of wind, PV, and other intermittent generation: The current generation mix in Europe is already characterized by large shares of renewable generation like wind and photo voltaic (PV), and these shares are likely to increase even further in the future. These types of generation have in common that they are volatile. In The-MA, these sources of generation are modeled with observed volatility. Like thermal and hydro plants, large wind parks or PV installations can be modeled individually with their own generation profiles and characteristics.

Modeling of area prices in Norway and Sweden: Sweden is modeled with the same four price zones as the market. Norway is modeled with seven price zones, and thus has a finer granularity than the setup of current price zones in the market. The division of Norway and Sweden is important in order to account for inner-Norwegian and inner-Nordic bottlenecks that may lead to price divergence between price zones.

Modeling of the integrated North-European electricity market including transmission capacities: As the Nordic market is highly integrated with neighboring countries in Europe and power exchange plays a crucial role for the price level and export/import opportunities, countries like Germany, Netherlands, Poland, and UK are included in the model (others may easily be added). The Baltics are modeled as an own price zone. Flows can be based on price differences (*implicit auction*) or contracted trade, or a combination of the two.

Appendix 3: Key model assumptions

Appendix table 1 shows assumptions for installed capacities in the reference scenario. Note that the numbers for coal, gas, bio, peat and fuel oils include combined heat and power extraction plants using these fuels. Hence, the numbers for these fuels do not represent condensing plants only. We have also excluded plants used in strategic reserves and plants owned by the TSOs to handle grid disturbances.

Appendix table 1. Installed capacities in the reference scenario (GW)

Fuel	Baltics	Denmark	Finland	Norway	Sweden
Coal	0.4	0.9	0.8	0.0	0.4
Gas	1.0	1.6	1.9	1.0	1.2
Nuclear	1.4	0.0	5.0	0.0	7.9
Oil	0.0	0.0	0.1	0.0	0.1
CHP	0.9	0.6	1.5	0.4	2.7
Hydropower	2.7	0.0	3.1	36.9	16.4
Wind	2.6	8.5	4.2	2.4	9.4
Solar	0.0	2.0	0.0	0.0	0.0
Bio	0.2	0.7	2.0	0.0	2.0
Peat	0.0	0.0	1.1	0.0	0.1

Appendix table 2 shows the assumptions for new interconnectors into the Nordic and Baltic region between 2015 and 2030.

Appendix table 2. New interconnectors out of the Nordic region up to 2030 in the reference scenario

Cable	Capacity
Sweden – Lithuania (NordBalt)	700 MW
Lithuania – Poland (LitPolLink)	1,000 MW
Denmark – Germany	1,000 MW
Norway – Germany (NordLink)	1,400 MW
Denmark – Netherlands (COBRA)	700 MW
Norway – UK (NSN)	1,400 MW
Norway – Netherlands (NordNed2)	700 MW
Sweden – Germany (Hansa PowerBridge)	700 MW

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Capacity adequacy in the Nordic electricity market

An increasing share of intermittent renewable generation and reduced profitability of conventional power generation has led to a growing concern for capacity adequacy in the Nordic electricity market (Nord Pool market area). It does not make sense to assess capacity adequacy for each country separately in the Nord Pool market area as it is highly integrated in terms of both interconnector capacity and market integration. Capacity challenges are rarely isolated to one country or bidding zone. This report analyses what market solutions may be used to manage capacity adequacy in the Nord Pool market area, and how an efficient transition to adequate market solutions could be achieved. The main analysis reveals several measures that would strengthen price formation and cost recovery in the Nord Pool market area, although in general, the market is already highly liquid and well-functioning.

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