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# TECHNICAL REPORT



SUBJECT/TASK (title)

## Vulnerability of the Nordic Power System

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### RESULT (summary)

The objective of the analysis is to identify the vulnerability of the Nordic power system, identify barriers to reduce vulnerability in a Nordic context and to propose possible actions. The study focuses on vulnerability with respect to energy shortage, capacity shortage and power system failures.

Vulnerability is defined with respect to the unwanted situations "High prices", "Curtailement" and "Blackouts". The main tool of the study is risk analysis, where risk is a result of the probability of an event and its consequences.

With respect to energy shortage, the system is in a medium risk state. For the present system the probability of a situation like the 2002/03 winter or considerably worse is once every ten years. Under the assumption that power production increases with increasing demand, the situation will be similar towards 2010. In the opposite case, the risk of extremely high prices increases. With respect to capacity shortage, the system is in a low risk state. This is partly due to actions already taken by the TSOs. The risk state will slightly deteriorate towards 2010. With respect to blackouts, the system is in a medium risk state. This is due to the fact that large blackouts in Southern Scandinavia cannot be completely ruled out. Such blackouts involve many consumers resulting in major or potentially even critical consequences. However this is not different from the situation before deregulation. There are no indications that the situation will become worse towards 2010, but there is uncertainty with regard to the effect of changed maintenance routines. Reductions in qualified technical personnel also gives reason for concern.

The study identifies significant differences between the Nordic countries with respect to the framework for transmission system investment, system balancing, rules and price setting in the case of curtailment, congestion management and the handling of import and export. Recommended actions include reduction of regulatory uncertainty with respect to generation investment, improving demand elasticity, reducing the impact of high prices on specially exposed consumer groups, improving the framework for grid expansion, improve system monitoring and protection and operator training and increased research and development within power systems.

### KEYWORDS

SELECTED BY AUTHOR(S)	Nordic Power System	Energy Shortage
	Security of Supply	Capacity Shortage

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## LIST OF ABBREVIATIONS

ATC	- Available Transfer Capacity
CHP	- Combined Heat and Power
CPI	- Consumer Price Index
EBL	- Norwegian Electricity Industry Association
EBL-K	- EBL's mediator of research and development
EMPS	- EFI's Multi-area Power market Simulator
EMV	- Finnish Energy Market Authority
ENS	- Energy Not Supplied
GDP	- Gross Domestic Product
GWh	- Gigawatthour ( $10^6$ kilowatthour)
HVDC	- High Voltage Direct Current
ISO	- Independent System Operator
kV	- kilovolt (1000 Volt)
MW	- Megawatt (1000 kilowatt)
MWh	- Megawatthour (1000 kilowatthour)
NCM	- Nordic Council of Ministers
NTNU	- Norwegian University of Science and Technology
NVE	- Norwegian Water Resources and Energy Directorate
RCOM	- Regulation Capacity Options Market
RRC	- Regulation and Reserve Capacity
SPS	- System Protection Scheme
STEM	- Swedish Energy Authority
SvK	- Svenska Kraftnät, the Swedish TSO
TSO	- Transmission System Operator
TWh	- Terawatthour ( $10^9$ kilowatthour)
UIOLI	- Use It Or Lose It
VAT	- Value Added Tax
VLL	- Value of Lost Load





## **1 INTRODUCTION**

### **1.1 BACKGROUND**

This is the main report from the vulnerability study of the Nordic power system. An Executive Summary is available as a separate report [1].

In recent years Nordic electricity market cooperation has increased. Authorities and institutions at various levels presently work with improving the efficiency and reliability of this market. The importance of a more binding and coordinated Nordic power market cooperation has been further accentuated by last winter's strained power situation, and focus has been directed towards the individual countries' security of supply.

The blackouts in the autumn of 2003 have directed the attention towards the common Nordic vulnerability. A common statement from the minister meeting in Gothenburg in the autumn of 2003 expressed that: "The Nordic energy ministers acknowledge the need to carry out a vulnerability analysis of the Nordic power market to reveal common challenges related to questions around security of supply. The analysis shall include investigations on what can be done to avoid power cuts like those that occurred in September 2003. As soon as the causes of the problem are known, this shall be followed up and afterwards discussed by the meeting of the energy ministers in Brussels in December."

The meeting of the Nordic energy ministers in December 2003 agreed that the Nordic power market generally functions satisfactory, but that society's increasing vulnerability for power system failures make it desirable to carry out a comprehensive analysis of the vulnerability of the Nordic power system to identify specific action to improve the security of supply.

There are a number of indications for the need to analyze the vulnerability of the Nordic power market:

- The margin between installed generation capacity and peak demand has decreased after deregulation
- Electricity consumption has increased, while there has been no corresponding increase in new generation capacity. The Nordic energy balance is also strongly influenced by variations in inflow to the hydro plants, which was illustrated by the strained situation in the winter of 2002/03.
- The blackouts in the autumn of 2003 show that a number of unique, coinciding technical failures that are deemed to have low probability, can have significant consequences. The vulnerability of society for power interruptions has increased.

Control and improvement of the Nordic vulnerability requires coordination at the political level, between regulators and between system operators. With the objective to further develop the Nordic power system, the Nordic energy ministers have met regularly since the signing of the Louisa agreement in 1995, and further agreement has been reached on several principles for continued development. An important principle is the use of market-based solutions. In accordance with

political priorities in the Nordic countries, proposed actions to improve vulnerability shall be based on the following principles:

- Market prices shall balance demand and supply. This implies that prices reflect both the capacity and the energy balance.
- High prices are not a sufficient reason to intervene in the market. Among others, this is important to balance demand and supply and for the market participants' confidence in the market price with respect to investment in new generation capacity.
- Increased cooperation between various Nordic authorities and system operators is necessary to ensure the security of supply, including planning and expansion of the Nordic grid.

After a tender procedure, EBL-Kompetanse was selected to perform the study on behalf of the Norwegian Electricity Industry Association (EBL). Because of the importance of the question of vulnerability, EBL-K increased the budget provided by the Nordic Council of Ministers and engaged SINTEF Energy Research to carry out the study. It is the intention of EBL to continue the present study with two additional studies:

- **Evaluation of proposed actions to improve the security of electricity supply in the Norwegian power system**  
Socio-economic analysis of different actions. Evaluation and prioritization of different energy solutions, production technologies and market incentives to improve the security of electricity supply. The influence of different market solutions will be evaluated.
- **Harmonising and coordination of system operation within the Nordic power system**  
To develop a best possible functioning Nordic Power Market with common principles for tariffs, congestion management, system services, balance accounting etc., and agreed rules for sharing of investment cost.

The present report is the result of the study for the Nordic Council of Ministers by SINTEF Energy Research. The report is organized as follows:

The remainder of this Chapter describes the objectives of the study, gives some important definitions for the report, discusses vulnerability criteria and finally describes and limits the scope of the study. Chapter 2 gives a comprehensive description of the basic methodology for the study. The main idea is to identify unwanted situations and assess their probability and their consequences. An effort is made to classify consequences, but is acknowledged that such classification always will have elements of judgment. This is no less the case for the acceptability of risk – what level of risk is acceptable is ultimately a political decision. As a background to these questions, Chapter 2 concludes with a survey of some background literature, focused on consequences of blackouts. Appendix 1 Appendix 2, and Appendix 3 present the detailed analyses of the three main areas of concern: energy shortage, shortage of generation capacity and transmission system failures resulting in blackouts. Chapter 3 sums up these analyses and shortly discusses coincidence between these areas of concern. Chapter 4 discusses areas where differences in judicial basis, regulations and interpretation of roles form potential barriers to further integration of the Nordic Power Market with respect to reduction of vulnerability. Finally, Chapter 5 proposes a number of actions.

As a guide to reading the present report, the authors would recommend to read through the present Chapter to get an overview over the complete study. Readers short of time can jump over Chapter 2, but they will miss the justification of the chosen classification of consequences, which may make it harder to understand and accept later conclusions. As a compromise, at least Section 2.4 should be (skim) read.

Besides the authors, the following persons have contributed:

- Professor Ivar Wangensteen, NTNU (discussions of high prices and curtailment)
- Professor Arne T. Holen, NTNU (discussions on Chapter 2 and Appendix 2)
- Consultant Tor-Odd Berntsen, PhD, Adapt Consulting (Chapter 4)
- Associate Professor Richard Christie, University of Washington (discussions on Chapter 2)

Notwithstanding these valuable contributions, SINTEF Energy Research is solely responsible for the report.

## 1.2 OBJECTIVES

The objective of this vulnerability analysis is to

- 1) Identify incidents, situations and scenarios leading to critical or serious consequences to the society and the power system
- 2) Identify barriers to handle and reduce the vulnerability
- 3) Identify possible countermeasures and actions to handle and reduce the vulnerability

The terms incidents, situations and scenarios comprise the following three aspects as well as combinations of the three:

- Energy shortage
- Capacity shortage
- Power system failures

The criteria for the degree of criticality or seriousness related to the different situations to occur are defined below. In the following the term **situation** is used as a collective term for incidents, situations and scenarios if not explicitly defined/described. Examples of such situations are risk of energy curtailment, shortage in generation capacity during peak load and cascading outages. The specific situations to be further analysed will be the result of the identification and classification described in the next Chapter.

## 1.3 DEFINITIONS

In this Section some of the central concepts are defined for reference purposes. Most of the concepts are discussed in more detail in other parts of the report.

**Balancing market**

The market the TSOs use to match demand and supply in real time. This market has different names in the respective countries, but a very similar function. In Sweden this is called the “Balanstjänst” (Balance Service), in Norway “Regulerkraftmarked” (Regulating Power Market), in Denmark “Balancemarked”, while the Finish TSO uses the English term “Power Balance Services” on its web site.

**Billion**

The report follows the most common (US) definition, i.e. one billion equals  $10^9$ .

**Blackout**

A blackout is an unplanned and uncontrolled outage of a major part of the power system, leaving a large number of consumers without electricity. A “major” part of the power system includes at least parts of the transmission network, i.e. an outage in a large distribution network is not characterized as a blackout.

**Curtailment**

Curtailment is planned reduction of demand other than through market prices. Curtailment can be realized in several ways. A distinction can be made between physical curtailment by rotating disconnection or quota allocation.

**Energy shortage**

Energy shortage is associated with the power system’s ability to cover the energy consumption. It is characterized by reduced generation of electrical energy due to either scarcity of primary energy (water, fuel) or long term outage of major plants. In an import dependent area it can also be caused by unavailability of major interconnections. Energy shortage is a long term problem with a time horizon of, say one month up to several years. It is a question of price and volume rather than a physical supply attribute: In a free market there is in principle no lack of goods. It is a question of how high the price should be to balance supply and demand. Situations may however occur where the supply of electrical energy is so low that the authorities will not accept a market clearing by price but take measures to perform a controlled rationing or energy curtailment.

**High price**

In the context of an unwanted situation “High price” relates to abnormally high prices over a sustained period with the potential of damaging considerable numbers of households, businesses or the economy as a whole.

**Capacity shortage**

Capacity shortage is associated with the power system’s ability to cover instantaneous demand, characterized by lack of available capacity in the installed generation or in the transmission networks. This is normally a short term problem, with a time frame of a few hours, possibly over

several consecutive days<sup>1</sup>. Contrary to energy shortage situations, capacity shortage may occur so fast that there is no time for a market clearing, and the market may not be able to set a price.

### **Power system failures and faults**

A power system failure is an incident where a power system component's ability to perform its function is interrupted or reduced [2], [3]. The failure leads to a fault that is a condition where a component has a missing or reduced ability to perform its function. The fault may further lead to a power system forced outage. Faults may be caused by deficiencies in power system components (generation or transmission), system protection or inadequate routines and procedures.

### **Forced outage**

A forced outage is a circuit breaker tripping, enforced or unintended disconnection, or unsuccessful connection caused by a power system fault. A disturbance may develop into a blackout.

### **Risk**

Risk is the result of the consequence of an unwanted situation and its frequency of occurrence. Consequences in the present context are death or injury of people or loss of economic value. If everything could be quantified economically, one could say that risk is the product of frequency of occurrence and economic impact. Events with relatively low impact but high frequency of occurrence can represent the same risk as events with high impact but low frequency of occurrence. In the case of power systems, an example of the former is a two-hour outage of a part of the distribution system. An example of the latter is a blackout of a major part of a power system. In practice not everything is quantifiable, and a judgement must be used to evaluate risk.

### **Unwanted situation**

An unwanted situation is a situation with real or potential death or injury of people or loss of economic value. In the present study unwanted situations are restricted to:

- High prices for electricity
- Curtailment of electricity
- System blackout

### **Vulnerability**

The vulnerability is an expression of the system's lack of ability or reduced ability to withstand an unwanted situation, limit the consequences, and to recover and stabilize after the occurrence of the situation [4], [5].

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<sup>1</sup> In principle a capacity shortage can have a structural character, which means that it will occur on an almost daily basis continually. This is a typical situation in a number of developing countries, and could occur in industrialized countries after a severe disruption of the power system.

## 1.4 VULNERABILITY CRITERIA

The consequences of an unwanted situation to the society may occur in different categories such as [6]:

- Health and safety
- Economy
- Environment
- Reputation

In this study we focus on the human and economic factors: Health and safety as well as Economy. There are considered to be no major environmental consequences related to neither of the aspects focused in this study (capacity or energy shortage, or power system failures). Reputation may certainly be important to the different actors in the electricity supply. However this is considered of secondary importance when it comes to consequences to the society or the power system.

Examples of consequences related to major deficiencies in the electricity supply are given in Table 1-1 for the two categories Health and safety and Economy.

Table 1-1: Examples of consequences

Health and safety	Economy
Hospitals and nursing homes Safety related to stop of elevators, metros, traffic lights, heating etc. Food and water supply	Infrastructures (transport, information and communication, water supply etc) Loss of production and associated interruption costs High energy prices Loss of jobs

The consequences of different unwanted situations will be quantified as far as possible using a mix of human, technical and economic indicators or variables such as the following:

- Number of people affected
- Duration of the situation
- Energy price in €/MWh
- Economic damage in Euros per situation
- MW or MWh curtailed

The power system consequences are defined and discussed in relation to the separate studies of vulnerabilities due to energy shortage, capacity shortage, and power system failures.

## 1.5 SCOPE OF STUDY

The vulnerability analysis is a methodical examination of the Nordic power system with the objective to determine the system's ability to withstand threats and survive unwanted situations by the identification of threats, quantification of risk and evaluation of the ability to stabilize the system. The methodology is described in next Chapter.

Threats are circumstances related to energy shortage, capacity shortage, and power system failures with the potential of causing an unwanted situation [4].

As mentioned the consequences to the society of unwanted situations will be outlined for the two categories Health and safety and Economy. The scope is not to describe the societal consequences in detail for problems within these areas. Typical consequences within the two areas are described in Ch 2.8 based on previous events and studies. If electricity supply deficiencies for instance threaten lives, it is out of scope to estimate the number of deaths that might be caused of an unwanted situation. Instead indicators such as number of people affected and duration will be used if these may be quantified. Likewise it is out of scope to estimate the total socio-economic losses. However this will be discussed and estimates are partly given.

The Nordic power system in this context comprises the power system in Finland, Sweden, Denmark and Norway at the voltage levels 110 – 420 kV. The vulnerability analysis is carried out for the present situation and for the future Nordic power system in 2010.

The study does not comprise vulnerabilities due to the following aspects:

- Threats due to sabotage, terror, acts of war or international political conditions outside the Nordic countries or EU
- The local effects (as opposed to the effects on the entire transmission system) of events such as transformer explosions or fire in transformer stations
- Incidents in the distributions networks even if they may have critical impacts on a local level
- Floods and dam break

## 2 METHODOLOGY

The methodical framework for the vulnerability analysis of the Nordic power system is described in this chapter. The description is based on references [5]-[9] and adjusted to the present study. The vulnerability analysis is carried out according to the following steps, shown in the flow chart in Figure 2-1:

- Identification of unwanted or critical situations
- Description of the causes: Which incidents may lead to the critical situation?
- Determination/evaluation of the probabilities for the occurrence of the critical situations
- Classification of the consequences
- Establishment of risk matrices as a basis for risk and vulnerability evaluation
- Identification of barriers to handle and reduce the vulnerability
- Identification of possible countermeasures and actions to handle and reduce the vulnerability

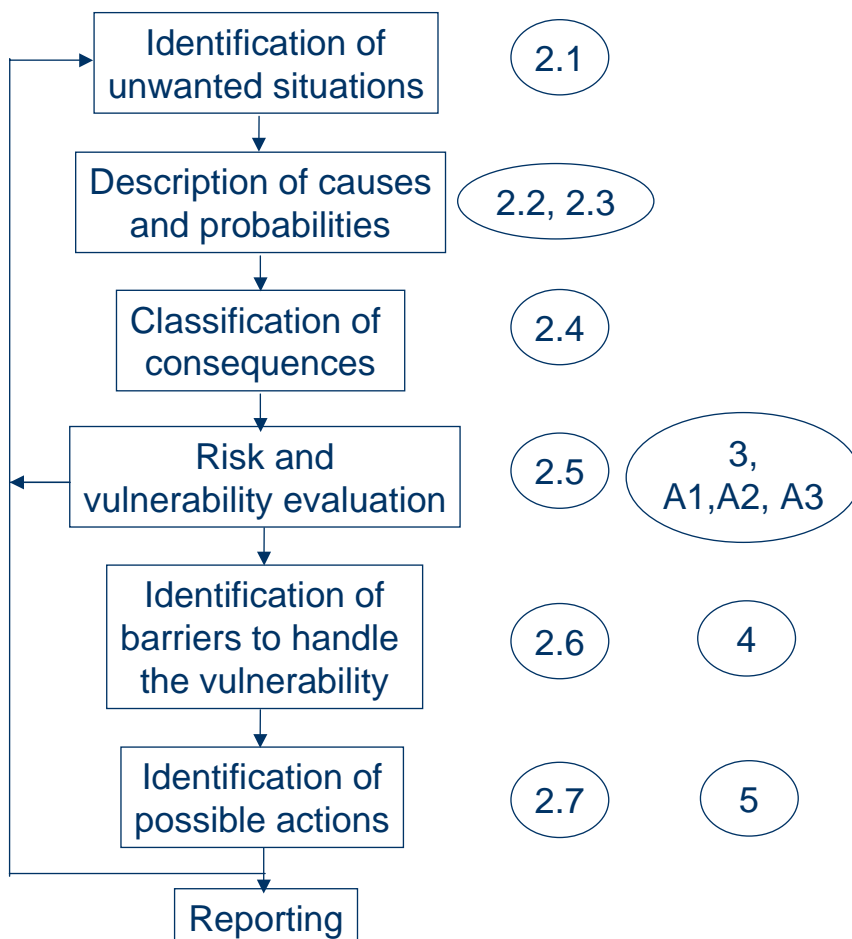


Figure 2-1: Flow chart for the vulnerability analysis

The different steps are described in separate sections as indicated to the right in the figure. The vulnerability analysis for the future Nordic power system is in principle carried out according to the steps as listed above, for different scenarios describing the development of factors such as



investments, electricity consumption, fuel prices and water inflow etc. This is described in relation to the separate studies of vulnerabilities due to energy shortage, capacity shortage and power system failures in Chapters Appendix 1, Appendix 2, and Appendix 3, which are summarized in Chapter 3.

## 2.1 IDENTIFICATION OF UNWANTED SITUATIONS

This step involves a systematic evaluation of the vulnerabilities due to possible threats within the different categories Health and safety and Economy. It is assumed that the most important factors in these categories for the society's vulnerability towards deficiencies in the electricity supply are **price** and **availability**. In this context the voltage quality is found to be of secondary importance. Price and availability are assumed to be reasonable indicators both for the human related and economic consequences of unwanted situations.

The types of consequences are grouped in three different categories describing the unwanted situations: "High price", "Curtailment" and "Blackout", as shown in Figure 2-2. A brief description of the three categories is given below and the categories are more specified in following sections.



Figure 2-2: Unwanted situations to the society

**"High price"**-situations means situations where the Elspot price is significantly higher than the normal level for a long period. Such situations are mainly related to energy shortage, in shorter periods also to capacity shortage.

**"Curtailment"**-situations means situations where a controlled rationing is effected, meaning load curtailment. There is necessarily not a clear distinction between "high price" and "curtailment". These aspects are related in the sense that curtailment might be necessary if the high price situation does not lead to a sufficiently decrease in demand to clear the market, or if the price level that clears the market is socially or politically not acceptable.

**"Blackout"**-situations means situations where the society experiences more extensive interruptions than what can be expected from the normal variations (according to the interruption statistics), meaning that larger geographical areas are affected more often and for longer periods than the normal variations.

High price for a longer period is the result of energy shortage in the Nordic market. Energy shortage may also lead to curtailment if either prices do not clear the market due to insufficient demand

elasticity or society does not accept the price level that is necessary to reduce demand. Curtailment may also be a short-term phenomenon in the case of generation capacity shortage during peak demand.

To identify possible unwanted situation it is important to determine “what happens if...”. The outline of unwanted situations will be based on a mix of sources or methods such as the following: Survey of previous events and studies, simulations by the EMPS model, dialogs and discussions with the transmission system operators (TSOs) etc. It is also coordinated with conclusions from previous studies and ongoing work, e.g. by the NCM Elgroup and Nordel.

Unwanted situations within the three categories are classified according to probabilities and consequences. This is outlined in the following sections.

## **2.2 DESCRIPTION OF CAUSES AND DEPENDENCIES**

Possible threats that might lead to unwanted situations are found among situations leading to energy or capacity shortage, power system failures as well as combinations of the three aspects.

For the probability assessment of unwanted situations it is important to survey the possible causes: Which situations or incidents may lead to the unwanted situation? The causes may be described for different categories such as

- Meteorological conditions (Examples: Low water inflow, weather conditions)
- Technical failure
- Human related failure
- Operational and maintenance practices
- Insufficient cooperation or coordination between TSOs
- Market handling

A description of possible causes, consequences and dependencies is given in the following event trees for the critical situations discussed above. The event trees are relatively high-level, and a more detailed discussion of the causes will be given in the respective chapters later in the report.

The following symbols are used in the event tree:

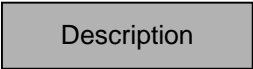
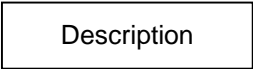



	Event, mainly long term
	Event, mainly short term
	Event, long and short term
	OR-operator
	AND-operator

Figure 2-3: Event tree symbols

The AND symbol means that the resulting event (on the left side of the symbol) will occur only if *both* the initiating events occur. The OR symbol means that the resulting event will occur if *any or both* of the initiating events occur. If none of the initiating events occur, the resulting event will not occur either.

The following figure shows the event tree for the “High price” critical situation.

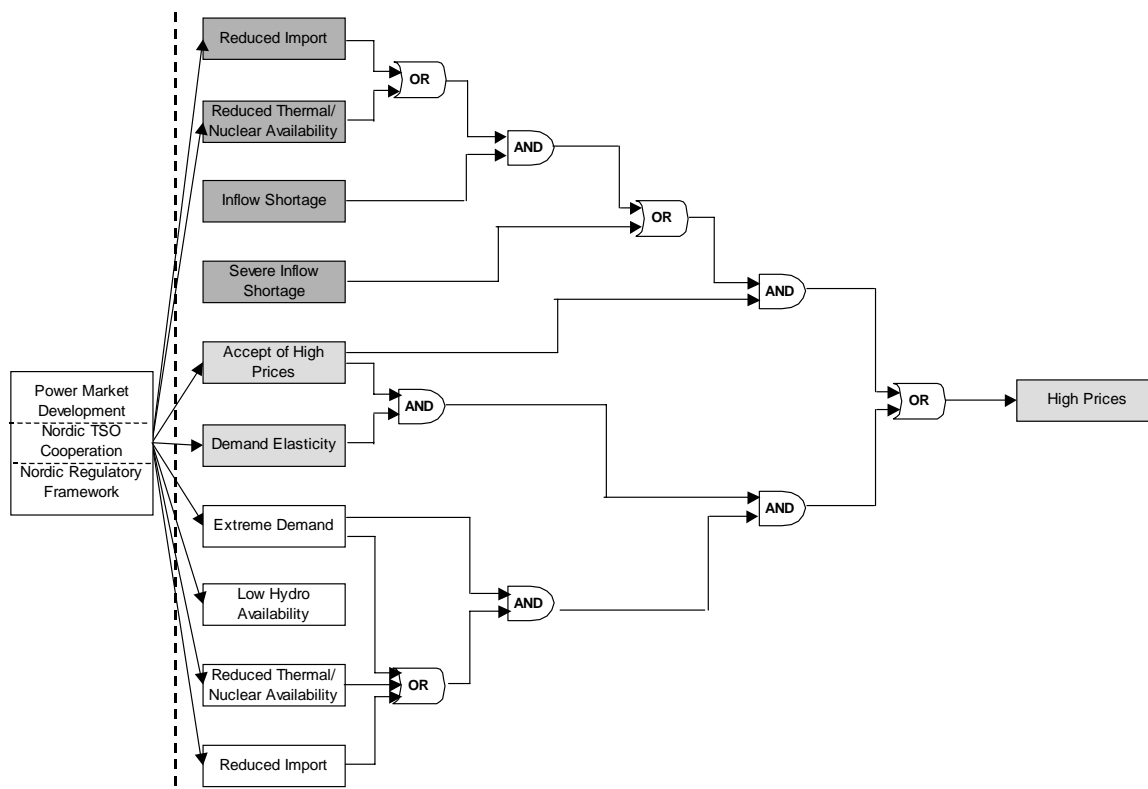


Figure 2-4: High-price event tree

The upper part of the event tree shows the causes to high prices related to energy shortage (a long term phenomenon), while the lower part is related to generation capacity shortage. In the context of vulnerability, we are concerned with “very” high prices. What is meant with “very” and how this is related to vulnerability is discussed in Section 2.4.1. Various forms of imperfect cooperation at the Nordic level might also raise average prices to some degree in normal situations. However, in the context of this study, this does not make the system more *vulnerable*, and such problems are therefore outside the scope of this study.

Prices may become high through either a severe inflow shortage, or a combination of a more regular inflow shortage combined with long term unavailability of either nuclear or thermal generation or reduced import availability, cf. the upper four boxes on the left part of the figure. There can be several causes to such reduced availability, but these are not shown in the event tree. In the case of thermal generation this could be caused by unfavourable conditions in the electricity market (i.e. low prices, illustrated by the development in Sweden in the late-90’s). Another reason can be reduced availability of either coal or gas in the Danish system related to a general shortage within the EU (cf. [10]). Nuclear power availability may be reduced by long term plant shutdown due to technical problems. Reduced import can be caused by major damage on a sub sea cable, or by power balance conditions in the countries exporting to the Nordic area. If this is combined with a political/societal accept of high prices (box “Accept of high prices”), then high prices will result. Without such accept, some form of curtailment will be necessary, cf. the discussion of Figure 2-5. The relation between high prices and curtailment will be discussed extensively in Section 2.4.1 in the context of energy shortage. The event tree above shows how high prices can result from either

an energy shortage situation (the upper part of the tree) or a capacity shortage situation (the lower part of the figure). It is obvious that high prices are more acceptable for a few hours, as in the case of a capacity shortage, than for several months. On the other hand, demand elasticity is lower in the short term.

The lower part of the figure illustrates the generation capacity related causes to high prices. Starting point is “Extreme demand”, together with one or more factors reducing supply (“Low hydro availability”, “Reduced Thermal/Nuclear availability”, “Reduced Import”). If there is sufficient short-term demand elasticity and an accept of high prices, again the result will be high prices.

On the left side of the dashed line, a box with important influences is connected with arrows to some of the event boxes. This is done to illustrate which events may be affected by Nordic TSO cooperation, a (potential) Nordic regulatory framework, and the general development of the power market. Ultimately these developments affect prices. Inflow and demand are outside the scope of TSO cooperation. Import (especially exchange between Nordic countries) is highly dependent on how the TSOs operate interconnections, and therefore on how they cooperate. Plant availability is not directly influenced by the TSOs, but net plant availability is a result of reserve requirements, among others, which is a TSO matter. Coordination of maintenance is another factor that influences plant availability. Demand elasticity can also be influenced by TSO policy, as well as rules that influence prices in (especially) the Balancing Market, and therefore the accept of high prices.

The next figure shows the corresponding situation for curtailment.

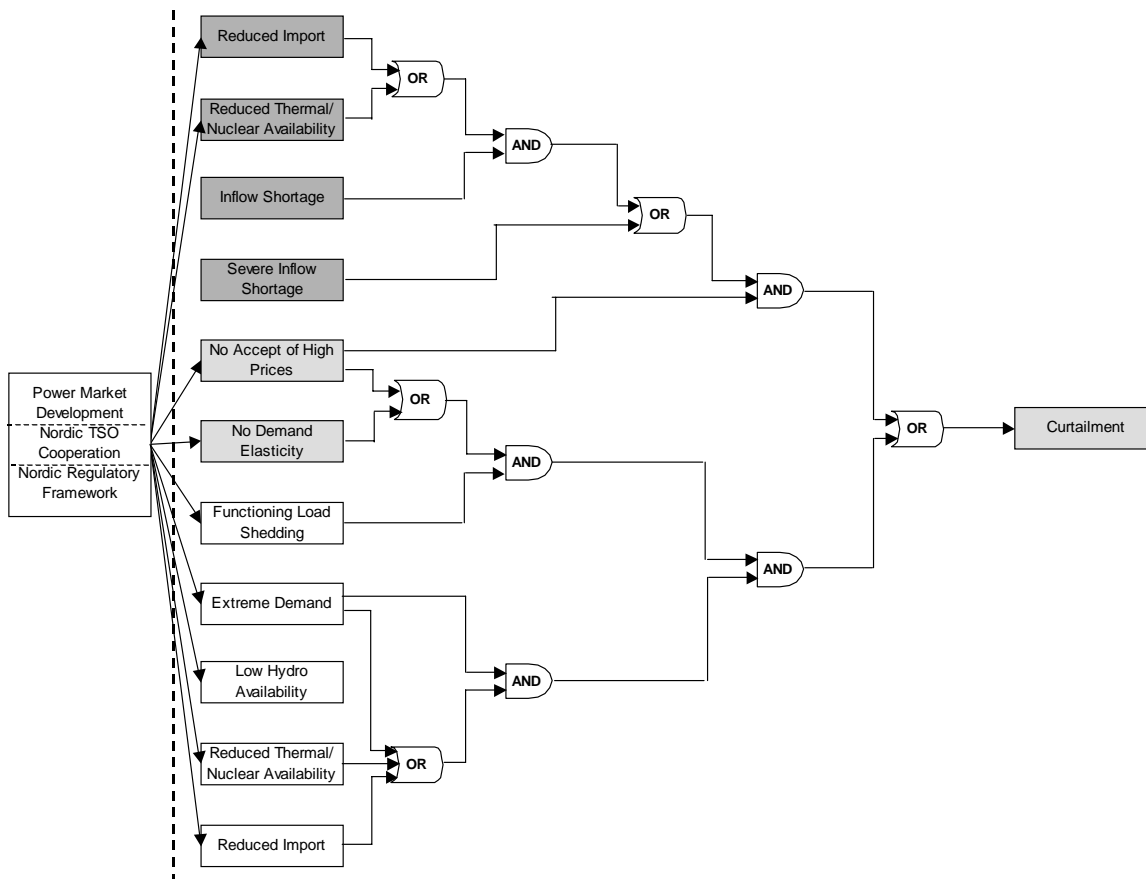


Figure 2-5: Curtailment event tree

The figure is very similar to the previous figure, and this illustrates the close relation between curtailment and high prices. Curtailment can either be a short-term phenomenon (a few hours in the case of capacity shortage) or a long-term phenomenon (reduced availability of power for one or several months in the case of energy shortage). There are some important differences between Figure 2-4 and Figure 2-5 that lead to the different outcome. In the case of energy shortage, the difference is that there is “No Accept of High Prices”. In this case a physical shortage must be solved by curtailment. In the case of generation capacity shortage, either “No Accept of High Prices” or “No Demand Elasticity” will create the basis for the necessity of curtailment. If involuntary shedding of demand by the TSOs functions well, the result will be controlled curtailment.

The arrows from the box to the left to the event boxes are mostly the same as in the previous figure. An important issue in relation to these figures is the rules and regulations governing situations with very high prices. To what level are high prices accepted in the short and long run in each country? What kind of hard or soft price caps are applied? On what basis is the market suspended and curtailment applied? This is one important area of Nordic cooperation that will be discussed further in Chapter 4.

The final event tree illustrates the high-level causes of a blackout.

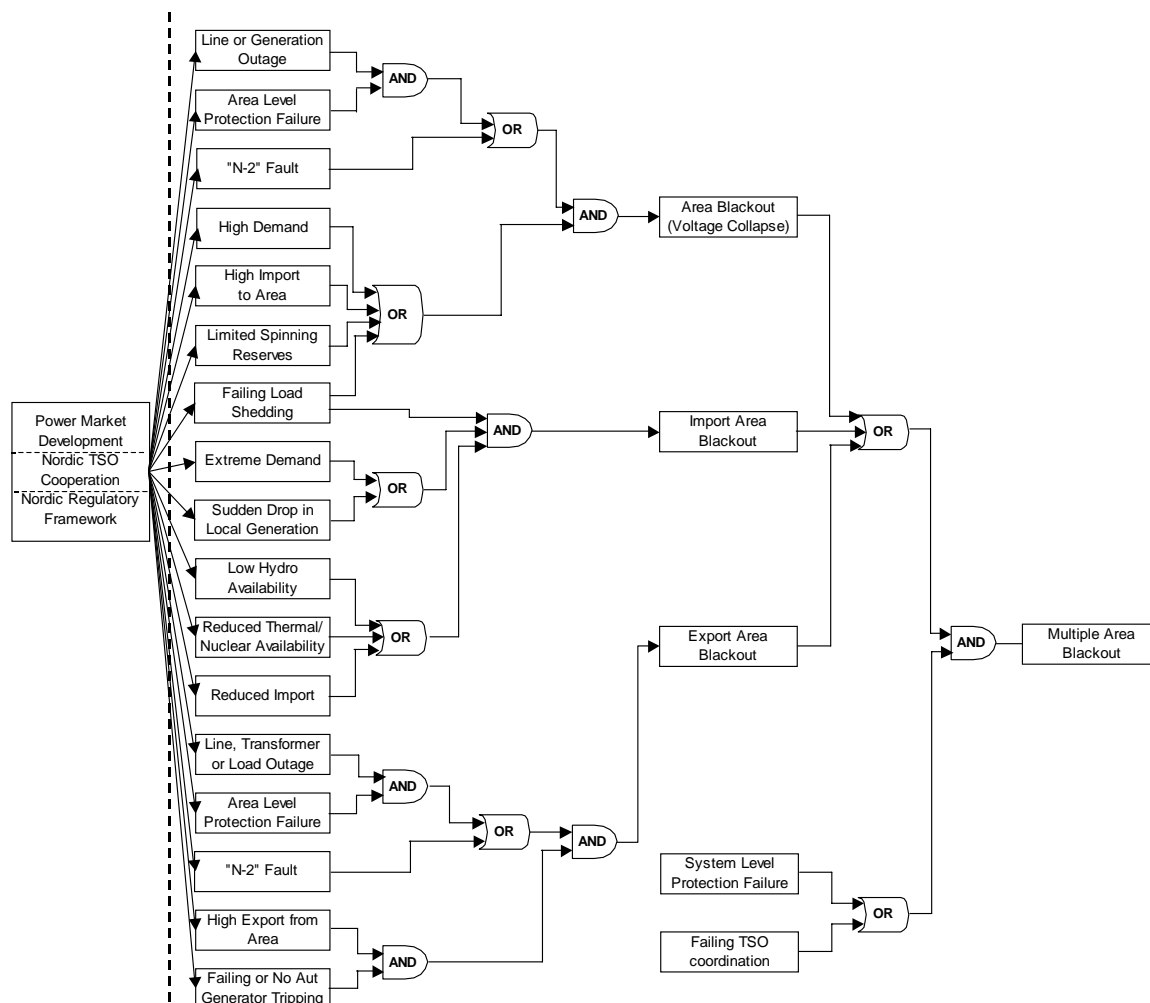


Figure 2-6: Blackout event tree

A blackout is related to either a generation capacity shortage or unplanned outages of generation, transmission or load. An energy shortage situation can change the probability of a blackout (in either direction), but does not in itself cause a blackout. The system state model in Figure 2-7 is commonly used when discussing power system security and the nature of a system blackout.

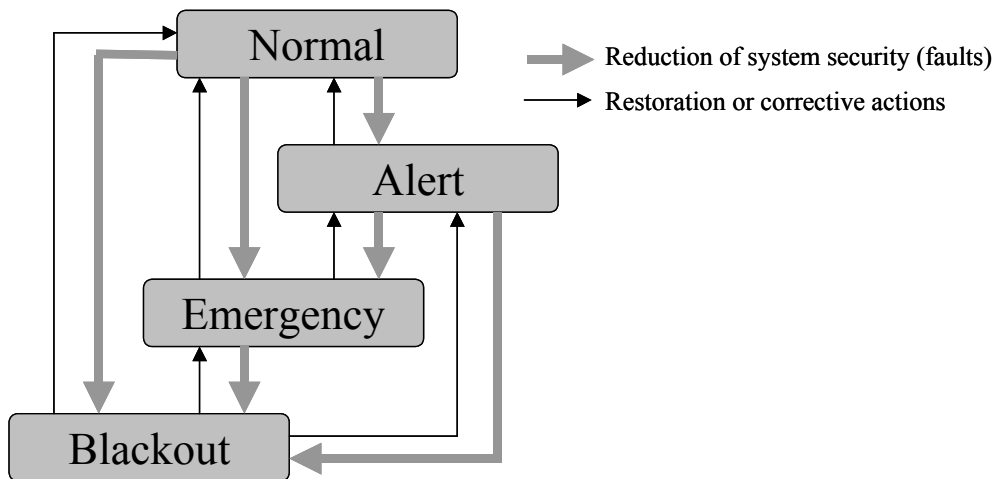


Figure 2-7: System state model

### Initiating events

Single faults combined with outage of a single line or generator should not lead to a blackout. According to the N-1 criterion, it should not even lead to loss of load. However, the system enters an alert state, and combined with failures of the protection system or e.g. mistakes during maintenance a more severe situation (emergency) can occur. Even if there has been no major disturbances, the system can in real-time operation be in the alert state (violating N-1 security) without the operators' awareness. Alternatively, a severe situation can be caused by the outage of a whole transmission corridor, e.g. in a situation of severe weather conditions. Two or more (independent) outages or faults within a short period of time will also cause an emergency situation. In the event tree this is denoted N-2 faults.

### Unfavourable conditions

In most cases an emergency situation caused by two independent faults will not lead to a blackout. This depends to a large degree on the operating conditions and to what extent the system is stressed. In the event tree we have identified a number of unfavourable conditions, such as "high demand", "failing system protection" or "high import or export", meaning that a transmission corridor is loaded to its limit. Unfavourable conditions increase the probability of a system entering an emergency or blackout state.

### Blackout scenarios

In the event tree we have distinguished between three basically different set of events that can lead to a sub-system blackout. The upper part of the figure describes events or combination of events that can lead to blackout of areas with low generation and high load (import areas). It is indicated that such situations very often end in a voltage collapse. In particular, this is the case if there is no protection to shed load or to separate the deficit area from the remaining system in the emergency situation.

Another potential cause of a blackout is related to the same combination of high demand and other factors as discussed in relation with the other event trees. Reserves are at their minimum when all generation and all flexible demand options are utilized. If generation still does not cover demand,



the only remaining solution may be to switch off demand involuntary. If this fails, the same sequence of events as discussed above may result.

The third scenario for area blackouts considers areas or sub-systems that operate at light load but with high generation, implying that there is a major power export from the area. It is recognized that under such conditions the power system is often less stable and more prone to power oscillations than when operating in a more balanced condition. When the transfer capacity is weakened by faults, possibly combined with loss of load that further increase power transfer, this may lead to undamped power oscillations that can cause a system breakdown.

### *Multi-area blackout*

A developing blackout situation can be stopped e.g. if sufficient load is switched off at an early stage, re-establishing a balance between demand and generation. If this has not been planned or does not work, blackout of a major area may result. Blackout of one area can easily cascade in blackouts of several areas as shown among others by the blackouts in the US and in Southern Sweden and Eastern Denmark in 2003. It can be avoided by a combination of sound system protection and well-functioning cooperation between the TSOs that are involved. In the opposite case, multiple area blackouts will result.

The part to the left side of the dashed line is discussed in connection with the previous figures.

## **2.3 DETERMINATION AND EVALUATION OF PROBABILITIES**

The probability<sup>2</sup> of occurrence of an unwanted situation is quantified as far as possible based on the previous description of the chains of causes. The quantification is based on sources such as disturbance and fault statistics from the Nordic countries (Nordel), time series of water inflow, experiences and expert evaluations (qualitative judgements).

The probabilities are expressed as frequencies and ranked according to how often the situations are assumed to occur. The categories and scale used are shown in the table below:

Table 2-1: Description of probability categories

<b>Probability category</b>	<b>Description</b>
Unlikely	Less than 1 per 100 year
Infrequent	1 per 100 year or more
Occasional	1 per 10 year or more
Probable	1 per year or more
Frequent	10 per year or more

<sup>2</sup> It should be noted that when we use the term *Probability* in this context, it is not strictly correct from a mathematical point of view. What we mean is the *Frequency of occurrence*, e.g. measured in [events per year].

In the results from the analyses shown later in this report, the categories “Probable” and “Frequent” are not shown. The reason is that events with a frequency of occurrence of once per year of more often do not make the system vulnerable. For such frequent events necessary counter measures are already taken, because they are obviously necessary.

## 2.4 CLASSIFICATION OF UNWANTED SITUATIONS

The consequences are described and ranked according to the degree of seriousness for each of the three categories of unwanted situations: “High price”, “Curtailement” and “Blackout”. The consequences are (as far as possible) measured in terms of a mix of indicators related to Health and safety and Economy as shown in Table 2-2.

Table 2-2: Consequence categories and indicators

<b>Consequence category</b>	<b>Health and safety</b>	<b>Economy</b>
Indicator	No of people affected Duration of the situation	Price in Euro/MWh MW or MWh curtailed Amount in Euros

With respect to health and safety, the number of people affected and the duration of the outage are important indicators. Other factors are the geographical extent of the event and the weather conditions. The geographical extent is important with respect to the opportunities to find alternative solutions to the problems that occur when power is interrupted. In the case of an outage in a limited area, power will be available not too far away from home. In that case, it will still be possible to buy basic necessities like food and fuel. This can be much more problematic when an outage involves large areas. Weather conditions are also important. In the Nordic climate, outages will be most damaging during cold winter days.

The number of people affected is not used explicitly in the analyses. The reason is that this is closely correlated to the number of MW that must be curtailed. Using both MW and number of people would in a way double count the size of the outage, while it is quite plausible that the duration of the outage is at least as important, cf. Section 2.4.3.

Economic indicators are most relevant when analyzing high price events, while size (in MW) and duration are more relevant when looking at outages. Although it is possible to measure the impact of outages in monetary terms using outage costs, the estimates become very uncertain when dealing with large outages of several hours or more. For durations longer than 12-24 hours during inadvertent weather conditions, there may also be danger for loss of human life. In such cases the question of what is an acceptable risk for society is more relevant than an estimation of costs.

We choose the following classification of the consequences of unwanted situations:

- Minor
- Moderate
- Major
- Critical
- Catastrophic

The boundaries between these situations are difficult to define exactly and highly dependent on judgement. Specific characteristics depend on the type of unwanted situation that is considered and will be discussed subsequently, but there are some common features. In this analysis we have tried to make the following distinctions:

### **Minor event**

A minor event has several of the following characteristics:

- Some deviation from normal situation.
- Not too many people affected.
- A short duration.
- No or minor media attention.
- No attention by the general public apart from those affected

Example: Half-hour outage in a medium-sized town like e.g. Trondheim

### **Moderate event**

A moderate event has several of the following characteristics:

- Considerable deviation from normal situation.
- Many people affected (say 100.000 or more).
- A certain duration (say more than two hours).
- Media attention.
- Attention by the general public and some damage (economic or emotional) experienced

Examples: High prices in the Nordic power market in 2002/03; Blackout in Western Norway in February 2004.

### **Major event**

A major event has several of the following characteristics:

- Large deviation from normal situation.
- Many people affected (say 500.000 or more).
- A certain duration (say several hours).
- Considerable media attention.
- Attention by the general public and damage (economic or emotional) experienced

Example: Blackout in Sweden and Denmark in 2003; Daily rolling 90-minutes power cuts in Italy of up 1700 MW of general users and 450 MW of industrial consumers in the week of 23-27 June 2003.

**Critical event**

A critical event has several of the following characteristics:

- Disruption of normal life
- Many people affected (say 1.000.000 or more).
- Long duration (8 hours or more)
- Unfavourable weather conditions (cold)
- Great media attention.
- Considerable damage (economic or emotional) experienced

Example: Auckland blackout in 1998.

**Catastrophic event**

A catastrophic event has several of the following characteristics:

- Huge disruption of normal life
- Loss of human life<sup>3</sup>
- Many people affected (say 1.000.000 or more).
- Very long duration (days)
- Unfavourable weather conditions (cold)
- Great media attention.
- Enormous damage (economic or emotional) experienced

Examples: Canadian ice storm in 1998; California power crisis<sup>4</sup> in 2001.

The examples are mostly from blackout situations, which are better documented than high price or curtailment situations, but some examples of the latter are also included.

In the following we will argue for how to classify the unwanted situations High price, Curtailment and Blackout within these categories.

**2.4.1 High-price****2.4.1.1 The relation between high price and vulnerability**

There are some methodical difficulties in the treatment of high prices and their relation with vulnerability. If electricity is regarded as just another good, there should be no reason why high prices for this good would give special reasons for concern. However, electricity has some special characteristics that distinguish it from other goods:

- It is generally regarded as a necessity (part of an infrastructure)
- In Norway and to some extent Sweden it represents a significant share of some households' expenditure
- At least in latter years, price variations have increased

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<sup>3</sup> Loss of human life, although the most severe consequence in any situation, does not automatically classify an event as catastrophic. E.g. a minor blackout may cause a traffic accident with fatal result.

<sup>4</sup> During the California power crisis end-users were not exposed to the extremely high prices on the spot market, at least not initially. Most experts agree that this was actually one of the reasons of the crisis. In relation to the subsequent discussion, it is somewhat inconsistent to classify this crisis as a catastrophic event, but on the other hand it caused rotating blackouts and a major and long-lasting disruption of the Californian economy to an extent that qualify for the term "Catastrophic".

In this context, we shall not forget the underlying rationale for a market-based organization of the power sector, which is to increase economic efficiency. In a market, supply and demand adjust dynamically to the market price. Fluctuating prices are therefore not something “bad” that has to be avoided, but a necessary element in a well-functioning market. Moreover, to make investments in new capacity profitable in a market environment, it is necessary that average prices cover all fixed and variable generation costs, including a risk premium to cover uncertainty. With the inherent significant variability of hydro generation, prices have to be high in some years to compensate for the low prices in wet years. Of course, extreme prices can be problematic and may indicate deficiencies in the market structure. But occasional moderately high prices are a natural ingredient in markets, especially markets with large variations in both supply and demand, like the Nordic electricity market.

In [11] an analysis is made of the macro economic consequences of the high prices for electricity in 2003. The analysis uses the macro economic model KVARTS, which has a quarterly resolution. Consequences are identified on:

- Norway’s real income
- Households’ disposable income, consume and saving rate
- Investments
- Export and import
- Gross domestic product (GDP)
- Employment
- Consumer price index (CPI)

The CPI increased with 1.3 percentage point for the year as a whole. Measured in fixed prices, households’ consumption was reduced with 0.3 percent, while households’ total consumption expenditure increased with 0.9 percent. The saving rate was reduced with 0.6 percentage point.

In addition to the effect of reduced demand from households, the competitiveness of export-oriented industries is reduced because of increased costs. Together with the direct effect of low power production and reduced household demand, this reduces GDP of Norway (excluding the oil sector) with 0.5 percent, measured in fixed year-2000 prices. The direct contribution of reduced power production constitutes one third of this. Disposable real income of Norway is reduced with 6.6 billion NOK (0.8 billion Euros) or 0.5 percent. There is only a marginal effect on employment [11].

To our knowledge, no similar analysis has been done for the other Nordic countries. Even if the effects on households’ disposable income were similar, the other effects on the economy may be quite different. Denmark, for instance, would have a considerable increase in power production for export to Norway and Sweden. So while Danish consumers faced more or less the same prices as in Norway, Danish producers profited from export revenues, which probably resulted in an increase of Danish GDP.

Macro economic analyses typically consider total amounts, and disregard distributional effects. In another study [12] the authors analyze how various groups of households were affected by the price increases. They divide households in ten income groups of equal size. As expected, there is a positive correlation between income and electricity consumption. As a result, the average increase in electricity expenses is calculated to 3172 NOK (386 Euros) per household per year for the lowest income group, and 5859 NOK (714 Euros) for the highest income group. However, there are a number of households in the lowest income groups that have a relatively high use of electricity. E.g. 17 percent of the lowest income group has an annual consumption in excess of 25000 kWh, and for a number of these households, high prices like in 2003 are problematic. On the other hand, many in these groups have various forms of support, which compensates the price increases to some extent.

In a study of the development in the power market in 2002-03 [13], the authors conclude that, looking back, the Nordic market handled the challenges of inflow shortage and resulting high price periods satisfactory. Based on the discussion above, the main problem of high prices, seems to be the position of low-income groups, especially those with high electricity consumption. Although many of these benefit from various support schemes, some will not satisfy the criteria for these schemes.

So far, we have discussed the effect of high prices resulting from energy shortage. High prices can also occur as a result of a shortage of generation and/or import capacity during extreme cold and resulting high demand. In this case, the duration of high prices is probably only a few hours, possibly several days in a row. E.g. on the day with the highest prices in Nordpool so far, 5 February 2001, had 8 hours with prices above 100 €/MWh. The level of such prices may become much higher. Nordpool has a technical price cap of approximately 1200 €/MWh, but this can probably be increased in special situations. Higher prices can also occur in the Balancing Market. In Norway, the price cap in this market is twice the price in Elspot, but at least 50000 NOK/MWh (appr. 6000 €/MWh). The question is to what extent this is a problem and if the possibility of very high prices during short periods represents a source of vulnerability in the Nordic system.

Presently only a small number of final consumers are directly exposed to the hourly spot price. Most of these are large consumers with high competence on their energy consumption. So this form of high prices does not present a problem for consumers. However, a study by Svenska Kraftnät in 2002 points out that this constitutes a considerable risk for traders and especially retailers [14]. Thus there is a certain vulnerability of the market itself, if several market participants would go bankrupt in such cases.

#### **2.4.1.2 Country-specific effects**

The economic effects of high prices depend on a number of country-specific characteristics. Electricity consumption as a share of total energy consumption gives an indication of the importance of electricity in a country's energy consumption, and hence of the relative effect of high prices on the economy as a whole. In the previous Section, we referred to several analyses from Statistics

Norway. The main impression is that the high prices in 2003 were not a major problem for the Norwegian economy as a whole, but that certain low-income households with high electricity consumption probably were severely affected. This fact and the political turmoil it causes may be the worst effect of high prices, and therefore it is important to focus on characteristics that highlight the importance of electricity in households' economy. The missing link is then the distribution of electricity consumption over income groups. This has not been readily available for the other Nordic countries, and we assume that the situation in the other countries is similar to that in Norway. Given the relative importance of electricity in Norway, this is probably a somewhat pessimistic assumption.

Another issue is the share of consumers with fixed contracts. In the short run, consumers with fixed contracts are less exposed to high spot market prices, and there was clearly a great difference between such exposure in Norway and the other countries in 2002/03. While consumers in the other countries mostly faced fixed price contracts, the major share of Norwegian consumers had "variable price" contracts, implying that retailers can adjust prices on a regular basis. However, the analysis in [13] shows that prices of fixed contracts increased significantly towards the end of 2002. As a result, the increase in electricity expenditure between 2002 and 2003 was probably of a similar magnitude for Swedish as for Norwegian consumers. This supports the assumption that in the long run, spot prices have a similar impact on consumer expenses, regardless of contract form<sup>5</sup>. The only difference is that with e.g. one-year contracts, the effect is spread over a longer period, and therefore less obvious. The downside of annual contracts is reduced demand elasticity on a seasonal basis. As a result, contract forms do not have an impact on the effect of high energy prices on the economy as a whole, but they may dampen the political turmoil because the effect on households is less pronounced in the short run.

Table 2-3 gives an overview over indicators of the importance of electricity in the Nordic countries. We use the word "power price" for the part of the electricity price that is related to electrical energy, as opposed to grid costs and taxes.

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<sup>5</sup> Of course, consumers who are lucky to buy a fixed price annual contract at the optimal time will be less affected by spot price increases. However, when many consumers buy such contracts, some are lucky and some are not, and the average effect of this will be a development according to expected spot prices.

Table 2-3: Indicators for the impact of high electricity prices

			<b>Sweden</b>	<b>Norway</b>	<b>Finland</b>	<b>Denmark</b>
1	Energy consumption (TWh)	TWh	411.9	236.4	293.3	181.9
2	Net electricity consumption	TWh	135.6	105.7	80.8	32.8
3	Net electricity consumption	Share of 1)	0.33	0.45	0.28	0.18
4	Household energy consumption	TWh	92.9	44.2	60.4	50.7
5	Household electricity consumption	TWh	41.9	37.0	20.6	9.6
6	Household electricity consumption	Share of 2)	0.31	0.35	0.25	0.29
7	Household electricity consumption	Share of 4)	0.45	0.84	0.34	0.19
8	Household electricity expenditure share of total household expenditure	%	3.2	3.0	2.3	2.4
9	Power price share of electricity price <sup>1</sup>	%	45.0	40.0	45.0	25.0
10	Household power expenditure share of total household expenditure	%	1.4	1.2	1.0	0.6

<sup>1</sup> Approximate share, including VAT on power price

This power price share indicates how a relative increase in the Elspot price will affect relative household expenditure on electricity. E.g. for Sweden, the electricity is estimated to constitute 3.2 % of household expenditure. The power price share of this is 45 %, which means that  $0.45 \times 3.2 \% = 1.4 \%$  is related to power generation. This means, everything else equal, that a doubling of the spot price in a whole year would give the average Swedish consumer an economic loss equal to 1.4 % of his or her expenditure. The numbers are based on 1999, which may cause some bias because electricity prices were low in Norway in that year.

The importance of electricity in the energy mix is clearly highest in Norway, somewhat lower in Sweden and Finland and considerably lower in Denmark. Households' share of electricity consumption (6) is rather similar for all countries, but households' electricity consumption as share of their energy consumption (7) is widely different. However, the estimated expenditure to the power share of the electricity bill as a share of households' total expenditure (8) is surprisingly equal.

As argued, high prices do not present a problem to the *average* consumer, but to groups of low-income households with high electricity consumption. In spite of the numbers in the last line of the table above, we believe that this problem is worst in Norway, given the high share of electrical heating. On the other hand, the numbers may indicate that high prices are a greater problem than earlier assumed for households also in the other countries.

#### 2.4.1.3 Classification of high-price situations

We now make a link between the observations of the impact of high prices and vulnerability. We have argued that the Norwegian economy absorbed the high prices in 2002/03 surprisingly well. However, experience from Norway shows that the pressure of public opinion on the political au-



thorities can become high. This may ultimately result in measures that reduce the efficiency of the electricity market. We choose to regard the combination of the effect on low-income groups and the possibility of ill-advised intervention as an aspect of vulnerability, and measure it by the direct economic loss of Nordic consumers, defined as a price increase compared with normal prices multiplied with total consumption<sup>6</sup>. This means that we regard the cost increase to consumers as the criterion to classify high prices.

Average consumer prices in 2003 in Norway were estimated to be 25 €/MWh (including VAT) above a normal level. Elspot prices did not vary much between countries in 2003. The direct economic loss to Nordic household consumers can therefore be estimated to 2.7 billion Euros including VAT, or roughly 2.2 billion Euros excluding VAT.

The average spot price in 2003 was about 37 €/MWh or roughly 12.2 €/MWh higher than could be expected in a normal hydrological year. The increase of 25 €/MWh to consumers in Norway is partly due to VAT, partly to retailers' hedging costs and partly to increased profits. We assume that the damage to consumers is proportional to the difference between the spot price and a "normal" spot price multiplied with *total* consumption, which for 2003 would amount to 12.2 €/MWh multiplied with 397 TWh (gross consumption in 2002) or 4.8 billion Euros.

Based on the discussion above, the consequences of the situation in 2002/03 are judged as "Moderate". We now make the following supposition: if the Elspot price would become 1 NOK/kWh in two months, it would become politically unavoidable in Norway to intervene in the market. This would have to include some form of physical curtailment<sup>7</sup>. It is arguable how such a situation should be characterized, but with increasing curtailment, there would be a critical situation. A price of 1 NOK/kWh would not occur suddenly. An illustration of an assumed critical scenario is given in Figure 2-8. In the figure the prices are given in NOK/MWh and €/MWh, a normal price of 200 NOK/MWh (24.4 €/MWh) is assumed, and the highest prices are assumed to occur in March-April. This would give an average spot price of 233 NOK/MWh ((40 €/MWh) over normal for the year as a whole, and an estimated economic loss to Nordic household consumers of 4.0 billion Euros and of 8.8 billions Euros to *all* Nordic consumers.

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<sup>6</sup> This is only a rough estimate. I [12] another measure, Compensating Variation, is used, which is theoretically more correct. However, the difference is not very large, and within the context of this project our estimate is acceptable.

<sup>7</sup> If one of the countries in the integrated Nordic market should decide on curtailment, this would be a major disruption of the whole market.

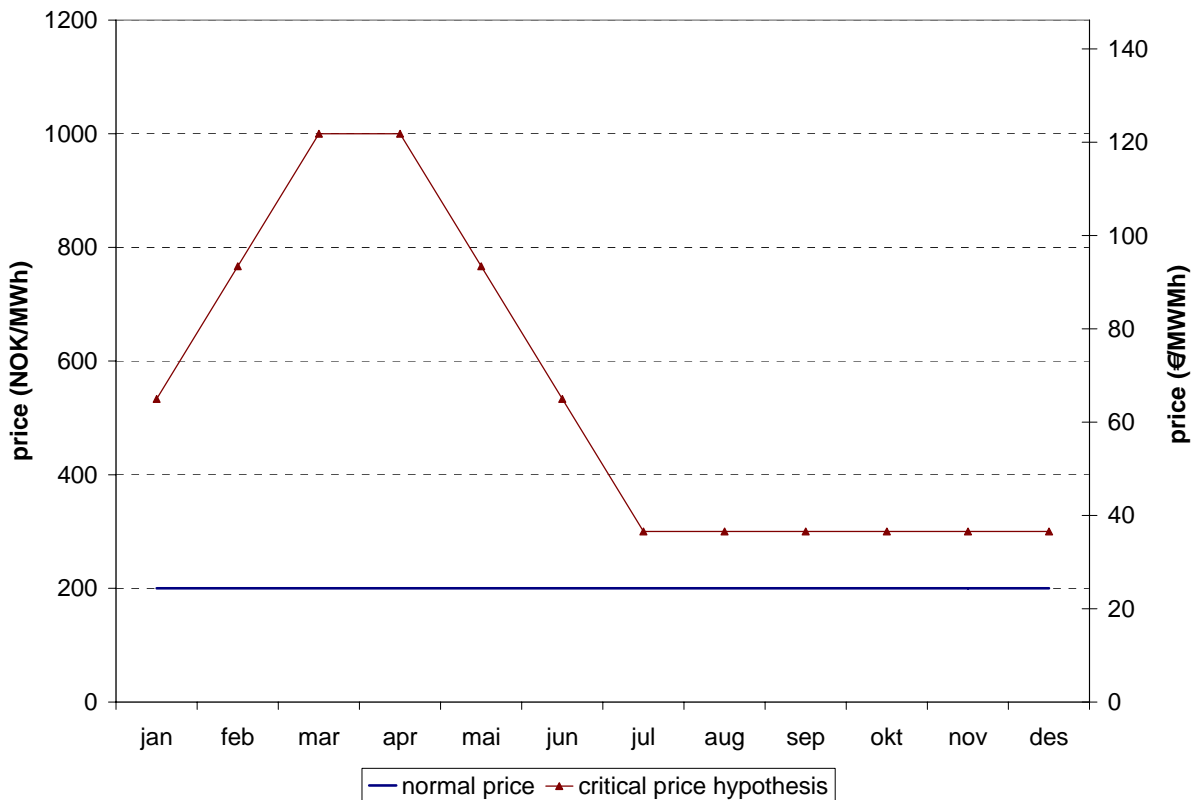


Figure 2-8: Illustration of critical price development that may lead to regulatory action and physical, non price-based curtailment

On this basis we end up with the following classification:

Table 2-4: Classification of High-price situations (excl VAT)

Direct economic loss to Nordic households	Corresponding loss to all Nordic consumers	Average spot price increase	Classification
< 1.0 billion Euros	< 2.2 billion Euros		None
1.0 – 2.5 billion Euros	2.2 – 5.5 billion Euros	25 €/MWh in one year	Moderate
2.5 – 4.0 billion Euros	5.5 – 8.8 billion Euros	36 €/MWh in one year	Major
> 4.0 billion Euros	> 8.8 billion Euros	> 36 €/MWh in one year, curtailment	Critical

Thus, in the context of energy shortage, minor events are not defined. Although it naturally would be possible to subdivide the outcomes below 2.2 billion Euros to all consumers in “Minor” and “No consequence”, we do not think this is fruitful in the context of energy shortage and vulnerability. Given the intention to let prices balance demand and supply, some price variation must be expected, and within certain limits, this cannot be seen as an “unwanted event”. Due to the difficulties in assessing the necessary amount of curtailment and demand elasticity in prolonged periods of very high prices, we have not attempted to find a limit where shortages could be classified as “Catastrophic”.

## **2.4.2 Curtailment**

We can recognize two types of curtailment:

- Curtailment due to energy shortage (primarily shortage of inflow to the hydro reservoirs)
- Curtailment due to a shortage of generation capacity

As discussed in the previous Section, curtailment due to energy shortage is probably not necessary, but it becomes the result of the (political) unwillingness to let prices rise to a level that reduces demand to available supply. We cannot preclude that such a situation may arise. This form of curtailment is discussed in Section 2.4.2.1 .

The other form of curtailment occurs when there is insufficient generation capacity available to match demand because of short-term inelasticity of demand. It is possible that this situation also can be avoided by letting prices rise to a level that clears the market, but in the presence of price caps this situation might arise. The circumstances that cause this situation are discussed in Appendix 2. Here we are concerned with how the classification of the situations, which is done in Section 2.4.2.2 .

Generally, curtailment is a controlled process, which primarily has economic consequences or at least consequences that can be expressed in monetary terms. A considerable share of total curtailment will probably come from the industrial sector. There is no danger for peoples' health and wellbeing, at least with the extent of curtailment that is conceivable in the Nordic system when sabotage, terrorism or warlike situations are disregarded. We therefore qualify curtailment as a critical situation, but never as catastrophic, at least in the Nordic system with reasonable assumptions.

### **2.4.2.1 Curtailment due to energy shortage**

In the Nordic system, curtailment due to energy shortage can be an option only in extremely dry years. The consequences of high prices are discussed in previous Sections and it is concluded that high prices can have a major impact on society. It can be preferred to resort to curtailment if the alternative is to see even higher prices.

Whether a specific situation will result in physical curtailment or “only” high prices is impossible to foresee, and will depend on a great number of factors. As far as we have ascertained, Norway is the only of the Nordic countries that has legal provision for curtailment through regulations for power curtailment [15]. According to paragraph 4 in these regulations, the rationing authorities shall inform the ministry [of Oil and Energy] when there is a real risk that a rationing situation will occur. The ministry decides effectuation and ending of rationing. Although not explicitly stated, it appears that the triggering event is a real risk for a rationing situation, and not high (or even extreme) prices. To our opinion, if this is taken literally, there is no need for rationing in an energy shortage situation on a national basis, at least in Norway, because prices are adjusted so fast that demand will be reduced sufficiently if only prices become high enough. However, in Norway it is conceivable that the need for rationing occurs in certain areas with limited intercon-

nections with the rest of the system. In such cases it is more difficult to use prices to reduce demand effectively, because there often will be only one dominating producer. Moreover, the volume to be curtailed may be higher relative to total demand than in the system as a whole, and there may be fewer flexible demand options.

On a national basis, we believe there is a limit to what prices are politically acceptable as argued in Section 2.4.1. Even if a situation could be solved by high prices and price elasticity of demand, it can still be argued that the situation is critical with respect to its impact on large groups of consumers and the credibility of the power market. Reference [16] describes in Chapter 6.5 how curtailment can be implemented gradually in situations where physical supply appears to insufficient to cover expected demand in the near future, e.g. before the spring inflow period. Initially information to consumers can be used to attempt to reduce demand. Subsequently, authorities (through the TSO) can limit generation within the area with the objective to maximize imports, and finally consumption can be limited. All consumers may be involved, but the authorities will try to minimize the economic cost to society. A detailed planning schedule for implementing rationing in distribution networks is given in [17].

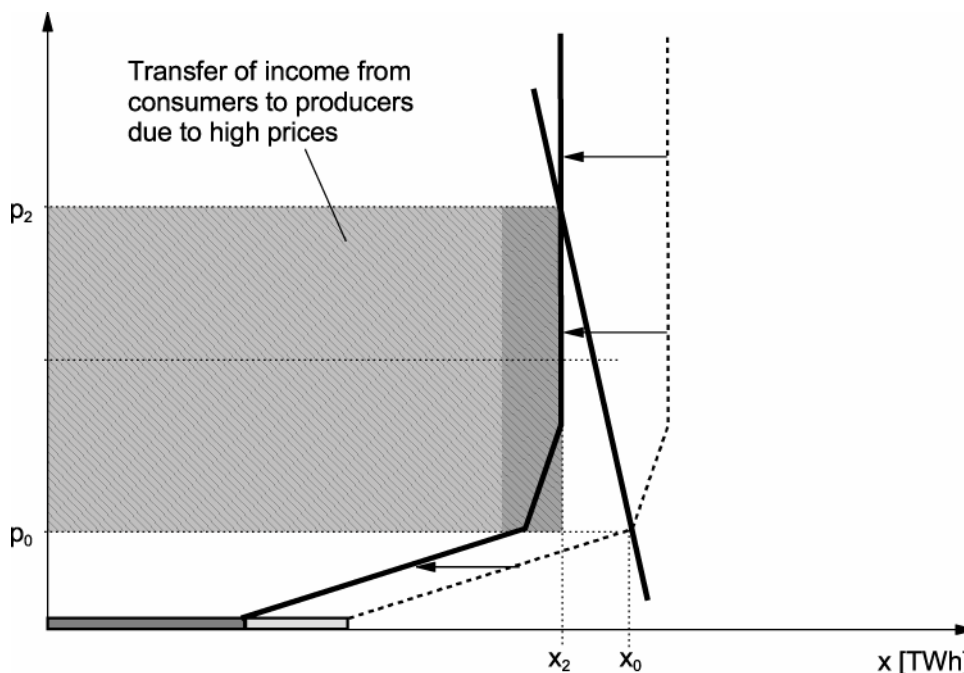


Figure 2-9: Income transfer from consumers to producers in the case of high prices

For a theoretical point of view, the situation can be as shown in Figure 2-9. We have a supply curve in a normal year indicated by the dotted line. The market balance, represented by the intersection with the demand line, determines the quantity  $x_0$  and the price  $p_0$  in a normal year. If there is a negative shift of the supply curve, in the Nordic system typically caused by a period of low precipitation, we get a new intersection with the demand curve. The quantity is now  $x_2$  and the price  $p_2$ . This represents the market solution. This is also the optimal solution in the traditional



Curtailment of electricity is generally difficult because electricity is basically a “self-service” product. Load shedding of some kind may be an ultimate alternative. We will not elaborate on how to implement curtailment here. We just emphasize that the price,  $p_3$  in the figure, representing the Value of Lost Load (VLL), can normally be assumed to be high compared to the intervention price,  $p_1$ . VLL is also higher than the corresponding market price  $p_2$ .

We can now compare the market solution, represented by the price  $p_2$  and the quantity  $x_2$ , with the solution based on curtailment. Curtailment represents a higher cost to the consumers exposed to load shedding than the corresponding willingness to pay. The difference between the two alternatives is indicated by the shaded area 1 in the figure. The extra cost to society (or the welfare loss) equals size of this area.

This welfare loss must be assessed against the economic consequences of relying on the market solution even in extremely dry years. By using curtailment instead of relying on the market solution, the income transfer from consumers to producers is reduced with the size of shaded area 2 in the figure.

These figures illustrate that curtailment is necessary primarily in order to avoid unacceptably high prices. In the case of energy shortage, it is always possible to establish a balance between supply and demand if prices were allowed to go up without any limit, but the central question is what price level is acceptable, and the what is an acceptable duration of such prices.

With respect to the distribution of an energy shortage between countries, it is from the outset clear that Norway has the most severe problem, given its almost total dependency on hydro power. The detailed analysis in Appendix 1 will further assess the potential occurrence of curtailment in the other countries as well.

As a final remark in this Section, we turn back to Figure 2-9, where the grey area exists of a dark and a light share. This is done to illustrate the effect of long term contracts. If consumers pay the spot price (or a price closely related to it), the income transfer is represented by the whole grey area in the figure. However, if consumers are hedged against high prices through long term contracts, the income transfer can be significantly reduced, at least in the short run. In this case only the dark grey area represents the income transfer. Although we argued in Section 2.4.1 that long term contracts did not make much difference, they do have the effect of spreading the income transfer over a longer period, making high prices more acceptable. On the other hand, this would also reduce the elasticity of demand. A solution that reduces uncertainty for consumers and at the same time keeps the incentive to react on high prices is a contract form where consumers buy a fixed amount of electricity at a fixed price, and the remainder at the spot price. This would combine the positive effects of long term contracts (hedging) and spot pricing (demand elasticity).

#### **2.4.2.2 Curtailment due to capacity shortage**

In Chapter Appendix 2 various situations are analyzed that may lead to a shortage of available generation capacity. In that chapter it is also described how the amount of curtailed energy related

to a certain shortage of capacity is estimated. The question is then how to classify capacity shortage events, based on curtailed demand.

There are three types of consequences of a deficit:

1. The direct damage to those consumers whose demand is involuntary curtailed.
2. The increased probability of blackouts of parts or even the whole system
3. The damage to the credibility of the power market

The *direct damage to curtailed consumers* in terms of energy curtailed is estimated in Chapter Appendix 2.

When the system is operated with very high demand and with a minimum of reserves, there is clearly an *increased probability of blackout*. However, within the constraints of the present study, it is not possible to quantify this effect. This must however be taken into account when evaluating the consequences of a capacity shortage.

A situation where there is insufficient generation capacity, and where demand must be curtailed involuntary will attract considerable attention from the media, and *damage the credibility of the power market*. On the other hand, occasional shortage situations with extremely high prices are necessary to discipline the market participants, and make them take their own risk limiting actions, which is the way a market-based system should solve the problem. If shortages and/or extremely high prices never occur, market participants cannot be expected to hedge against this risk. This is especially the case for retailers, who probably face most risk of extremely high prices due to capacity shortage in today's market, cf. [14]. An occasional extreme situation that hurts some market participants is probably a necessary condition to make market participants take the necessary precautions to reduce their own risk and through their collective effort the risk of the whole market. However, ideally it should not be necessary to curtail demand involuntary. If consumers have to be switched off involuntary, this will be seen as a kind of market failure, and as such damage the market's credibility. The effect is even more difficult to quantify than the previous point, but must be kept in mind when evaluating potential shortages.

A classification of outage situations based on MW affected and duration is given in the next Section for blackout situations. The question is if the same classification can be used for curtailment due to generation capacity shortage. An argument against this is that curtailment is planned, and more controlled and consumers have been notified, and these elements reduce the damage to consumers. Arguments for using the same classification are that a capacity shortage probably will occur in very cold periods, the probability of blackouts increases and the credibility of the power market is damaged. Weighing these arguments, we choose to use the same classification for curtailment due to capacity shortage as for blackouts, as given in the next Section.

### 2.4.3 Blackout

Classification of blackout situations should ideally be based on all the important factors that influence the severity of an event. Consequences of an event can e.g. be measured in terms of:

- Magnitude of the disturbance in terms of power interrupted (MW).
- Duration of the outage (Hour). Duration of a power outage due to a system collapse will of course vary as power supply is restored at different times in different areas. In this analysis we have defined duration to be the average duration obtained by dividing the total energy not supplied (MWh) with the interrupted power (MW).
- Other circumstances.

Magnitude and duration of a blackout are the consequences that are directly measurable and most easily predictable. Other circumstances include all other factors that contribute to the severity of a blackout, for example the number of people affected, injuries or loss of life, weather conditions and time of year, extreme damages to equipment and installations. Many of these factors can be regarded as functions of the magnitude and duration of the blackout, and thus the impact of these factors are to some extent included. However, some consequences that are obviously very important when assessing blackouts, may be difficult to quantify or estimate in advance. This is the case e.g. for the most critical consequences like loss of life. Such extreme consequences must of course be taken into account, but in our analyses they will only be considered when distinguishing between critical and catastrophic events.

As a basis to judge the severity of a blackout with respect to its duration, the following table from [18] is used to illustrate some consequences. Although the report is from 1984, most of the effects are very similar today, but the role of telecommunications and computers has increased significantly. This has probably increased society's sensitivity for a blackout. E.g. production in much of the service sector will stop completely as soon as computers become unavailable, but in a comparison with 1984 we should not forget that many activities would stop anyway because of their dependency on electricity.

Table 2-5: Sensitivity for blackout of various functions (without priority). Source: [18]

Time	Function	Consequence
1 second	Magnetic cranes Flight control Computers Process industry	Load can fall down Impact on air safety Loss of information and work Stop of processes with resulting several hours down time
10-15 minutes	Smelters  Computers with battery backup only	Floating material under transport must be recovered Systems stop, but no loss of information
15-30 minutes	Poultry farms Elevators	Animals may die It becomes unpleasant to wait in a stuck elevator



Time	Function	Consequence
	Underground	It becomes unpleasant to wait in a stuck train
30 minutes	Process industry Smelters	Stop of processes, down time of up to 24 hours Risk of hardening of ovens
2 hours	Pig farms Dairies Water supply	Ventilation problems, possible deaths of animals Reduced production Some areas start to loose water
6 hours	Smelters Greenhouses	Hardening of ovens, considerable economic losses Damage due to drying of freezing, depending on the time of year
8 hours	Water supply  Heating systems  Dairies	Risk of penetration of polluted water due to loss of pressure  Some buildings may start to become unpleasantly cold, problems for nursing homes Risk of illness and continued reduced production
10 hours	Telecommunication	Backup batteries emptied, traffic stops
12-24 hours	People and animals Road transport Food  Buildings  Wastewater treatment	Access to water and food Empty petrol tanks, filling stations not working Refrigerated and frozen food starts to get spoilt, problems with distribution to consumers Many buildings become very cold, beginning danger of frozen water pipes Risk of collapse of the water treatment with resulting long down times
Several days	Everyday life  Reserve power	Does not function. Many companies close. Severe problems with water supply, food and heating. Lack of fuel, need for maintenance, increased probability of failure

Reference [19], which also refers to [18] and [24], points at the fact that the consequences of a blackout depend on a number of other factors like:

*Geographical and demographical conditions.* The consequences become more severe if a large geographical area and more people (with certain share of needing people) are affected.

*Climatic conditions.* The consequences for households and in effect all buildings are more severe during especially cold weather. In warm periods there is a danger for spoiling of refrigerated and frozen food.

*Preparedness at the individual level.* Households may have alternative heating systems to some extent, though this only to a limited extent in towns. Other consumers can reduce damage if they have functioning backup generation for at least a part of their consumption.

*Collective preparedness and the availability of resources.* Municipalities play an important role in the initial handling of a crisis through information and services to those who are affected. An important issue is if municipalities have sufficient resources for this kind of crises.

Summing up, society appears to tackle blackouts of up to 12-24 hours without severe negative consequences, assuming that certain activities like hospitals and telecommunications have various forms of well-functioning reserve power. Long blackouts of several days severely disrupt society.

In order to carry out the risk analysis it is necessary to establish a quantitative description and classification of consequences. The quantification is done in terms of magnitude and duration of the blackout, and the chosen intervals and limits are based on the discussions above and the references provided. Table 2-6 summarizes the classification and intervals for blackout situations that will be used. The border between the different classes of events should not be interpreted as absolute, as they only cover the directly measurable consequences. Other circumstances must also be taken into account when possible, and especially if an event is close to the border between two classifications.

Table 2-6: Consequence classification and intervals for “Blackout”-situations

<b>Consequence classification</b>	<b>Power interrupted (MW)</b>	<b>AND Energy not supplied (MWh)</b>	<b>AND duration (hours)</b>
Minor	< 2000	<1000	< 2
Moderate	< 4000	< 4000	< 8
Major	< 8000	< 16000	< 18
Critical	< 32000	< 64000	< 32
Catastrophic	Otherwise (but strongly dependent on “other circumstances”)		

The border between the different classes can be plotted in a magnitude-duration diagram as shown in Figure 2-11.

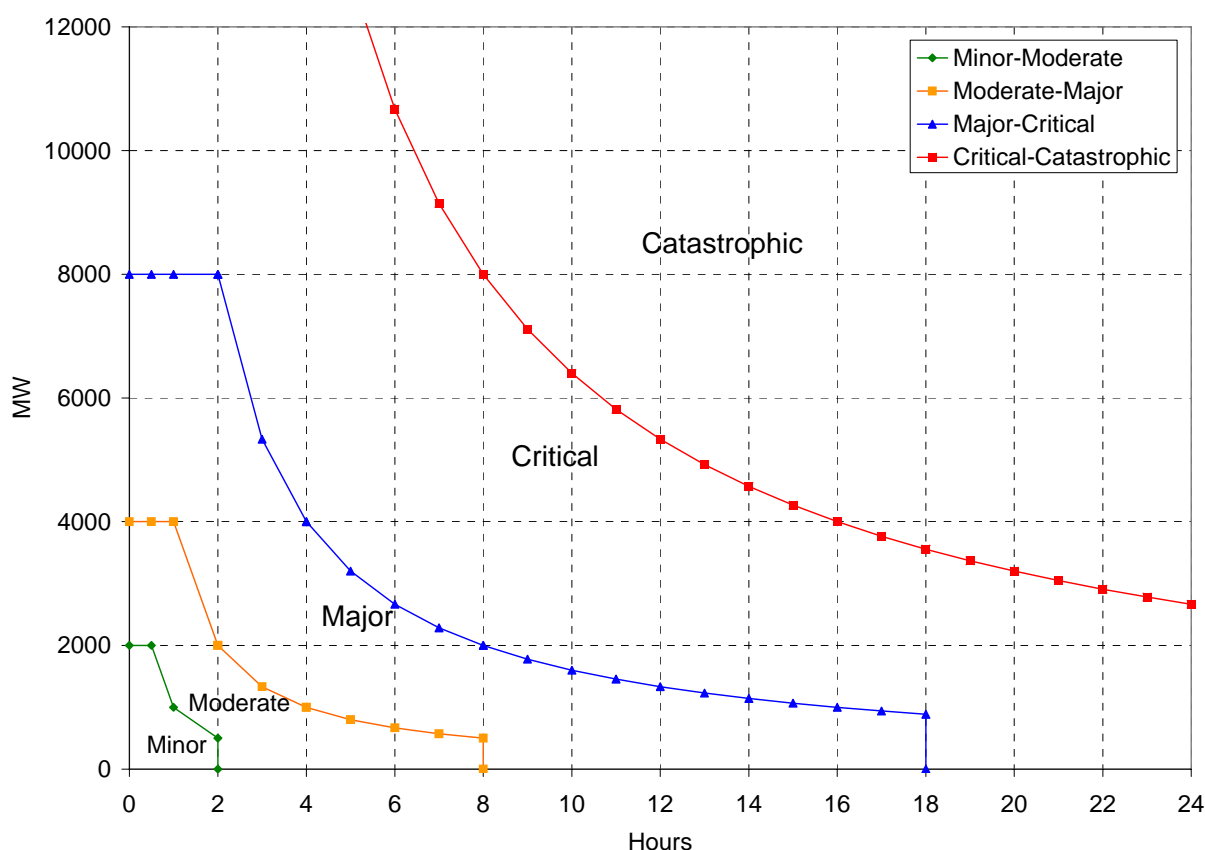


Figure 2-11: Consequence classification and intervals for “Blackout”-situations

## 2.5 RISK AND VULNERABILITY EVALUATION

The risk associated with the different unwanted situations consists of the product of frequency of occurrence and consequence. The estimates made according to the descriptions in the previous sections are put together in a risk matrix or risk graph. In this matrix the frequency of events increases on the vertical axis and the consequence increases on the horizontal axis as shown in the table and graph below:

Probability	Consequence				
	Minor	Moderate	Major	Critical	Catastrophic
Frequent					
Probable					
Occasional					
Infrequent					
Unlikely					

Figure 2-12: Risk matrix

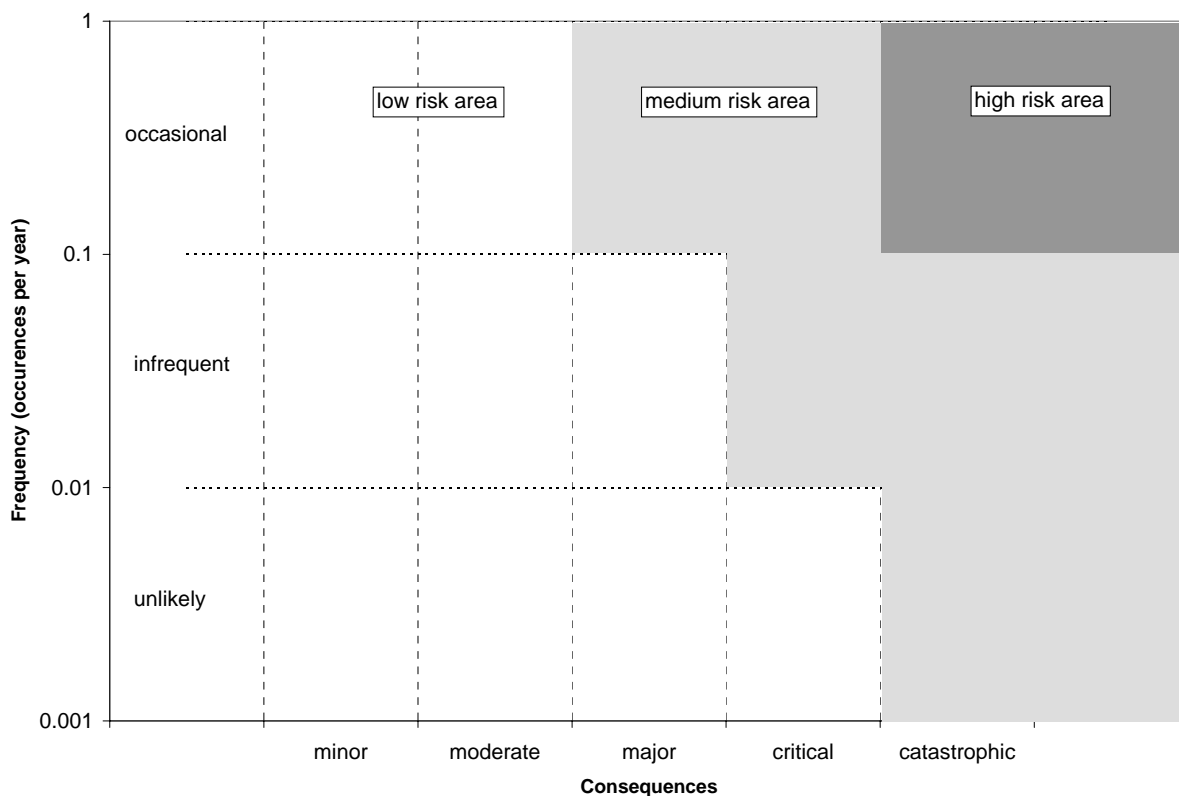


Figure 2-13: Risk graph corresponding to Figure 2-12

The quantified risk should be evaluated according to specified acceptance criteria. The criteria are typically divided in low, medium and high risk. A tentative division is indicated in the tables and graphs using the different degrees of shading as described in qualitative terms below:

	Low risk	Acceptable. No action requirements.
	Medium risk	Evaluation of needs and possibilities for risk reducing actions.
	High risk	Not acceptable. Risk reducing actions necessary

Definition of acceptance criteria is out of scope for this vulnerability analysis. However, this is an objective for the Nordic Council of Ministers in the evaluation of the results from the analyses reported. In this report the risk matrices will be established according to the scales defined in the previous sections for the probabilities and consequences. This gives a ranking of the unwanted situations for the different consequence categories and for different geographical areas in the Nordic countries.

The risk matrix forms the risk picture of a given unwanted situation. This is the basis for the vulnerability evaluation where the aim is to evaluate the system's ability to withstand threats and the ability to stabilize the system.

## **2.6 IDENTIFICATION OF BARRIERS TO HANDLE AND REDUCE THE VULNERABILITY**

Vulnerability is mainly, although not exclusively, a result of physical properties of a power system. The physical aspects are assessed in Appendix 1, Appendix 2, and Appendix 3. To the extent that conditions are revealed that call for actions to reduce vulnerability to an acceptable level, or to keep vulnerability at an acceptable level, it becomes of interest at what level these actions should be taken. Given the fact that we deal with one integrated Nordic power market, potential actions should be taken or at least coordinated at a Nordic level, to avoid actions that fail to support each other or even worse, that work in opposite directions.

In Chapter 4, evaluations will be performed on rules and agreements established in the common Nordic Power System, that can affect operation and investment decisions. The objective of this Chapter is to reveal potential conflicts between the laws, regulations and common practices between the individual Nordic countries that may constitute barriers to an efficient handling of power system vulnerability at the Nordic level.

## **2.7 IDENTIFICATION OF ACTIONS TO REDUCE THE VULNERABILITY**

Chapter 5 discusses various actions that could be taken to reduce the vulnerability of the Nordic power system. These actions are grouped in five groups:

- Improving the conditions for investment in generation
- Improving the framework for grid expansion
- Increasing the efficiency of the market
- Reducing consequences
- Research and development

It is important to remind of the basis for the present study (Section 1.1), emphasizing the use of *market-based* solutions. Thus “investment in generation” can never be an action at the political or authorities level, but “improving the conditions for investment” can. Also the other actions can be implemented at a political level, while leaving to the market to make the specific investment decisions.

## **2.8 LITERATURE SURVEY**

The literature related to power system vulnerability is virtually unlimited. A large share is within the classical engineering approach to power system reliability. Major questions assessed by this approach are how much generation and transmission capacity is necessary to obtain an acceptably low level of demand outage. In the context of this report we will not elaborate on this literature.

A number of references to existing literature have already been made in this report. This limited survey will shortly present some references that are important for understanding the concept of vulnerability, and the impact on society of major disruptions of the power system. Among these

are two reports of two major well-known outages. A similar report of the major outage in the US in August 2003 is not yet available<sup>9</sup>.

The objective of the **Danish Vulnerability Study** [4] is to describe the vulnerability of the Danish society and to give an evaluation of civil society's preparedness in relation to vulnerability. The basis of the study is the threats to society. These have changed because of globalization, technical development and increased specialization, terrorism and the end of the cold war. With respect to electricity, gas, telecommunications and IT, the major source of vulnerability is related to terrorist attacks. Vulnerability for technical failure with major consequences is seen as low, because these sectors have created a considerable degree of robustness. Some fear for decreasing robustness because of liberalization is expressed. Vulnerability of the power system is related to:

- The system's complexity
- Mutual dependency on foreign countries
- Dependency on important generation and transmission unit
- Existence of many unmanned units of high importance

Robustness is related to:

- High degree of preparedness for failures
- Large reserve capacity in generation and transmission
- Interconnection with foreign countries
- The System Operator's monitoring and controlling role

The **EU Green Paper** "Towards a European strategy for the security of energy supply" [10] has focus on Europe's growing dependency on energy import. The European Union is consuming more and more energy and importing more and more energy products. Community production is insufficient for the Union's energy requirements. As a result, external dependence for energy is constantly increasing. The dramatic rise in oil prices which could undermine the recovery of the European economy, caused by the fact that the price of crude oil has tripled since March 1999, once again reveals the European Union's structural weaknesses regarding energy supply, namely Europe's growing dependence on energy, the role of oil as the governing factor in the price of energy and the disappointing results of policies to control consumption. Without an active energy policy, the European Union will not be able to free itself from its increasing energy dependence.

Security of supply does not seek to maximize energy self-sufficiency or to minimize dependence, but aims to reduce the risks linked to such dependence. Among the objectives to be pursued are those balancing between and diversifying the various sources of supply (by product and by geographical region).

The Green Paper sketches out the bare bones of a long-term energy strategy, according to which:

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<sup>9</sup> Estimates have been made of the economic damage of the outage, e.g. , but in this context we are more concerned with the kind of consequences that consumers face, and that not necessarily can be expressed in monetary numbers.

- The Union must rebalance its supply policy by clear action in favour of a demand policy. The margins for manoeuvre for any increase in Community supply are weak in view of its requirements, while the scope for action to address demand appears more promising.
- With regard to demand, the Green Paper is calling for a real change in consumer behaviour. It highlights the value of taxation measures to steer demand towards better-controlled consumption which is more respectful of the environment. Taxation or parafiscal levies are advocated with a view to penalising the harmful environmental impact of energies
- With regard to supply, priority must be given to the fight against global warming. The development of new and renewable energies (including biofuels) is the key to change. Doubling their share in the energy supply quota from 6 to 12 % and raising their part in electricity production from 14 to 22 % is an objective to be attained between now and 2010.

Identified risks are:

- Physical risks, related to exhaustion of one or more energy resources (specifically oil and gas) at a reasonable cost.
- Economic risks, caused by erratic fluctuations in the price of energy products on the European and world markets.
- Social risks linked to erratic fluctuations in prices, relations with producer countries or a chance event. In this context it is mentioned that a serious disruption of the supply of petrol is similar to that created by a bread shortage two hundred years ago.
- Environmental risks caused by the energy chain, either accidentally or as a result of emissions.

The Norwegian **Vulnerability Study** [22] initially points out that a common characteristic of many large accidents is that it is easy to see afterwards what should have been done differently. An important part of preparedness is to learn “to have hindsight beforehand”. The committee that has done the study concludes that society generally has become more vulnerable because the failure of only a few important functions can have severe effect on the whole society. Power supply and telecommunications are mentioned explicitly. Circumstances contributing to this development are:

- Technological change
- Increasing complexity
- Increasing cost awareness and efficiency pressure
- Reduction of number of employees in many businesses
- Privatization of public services

With respect to the power system, the study points at regional vulnerability related to adverse weather conditions. Another point is the effect of increased rationalization and focus on cost efficiency in the wake of deregulation. Potential occasional shortage of generation capacity is mentioned explicitly, as well as the ambiguous effect of strong interconnections and cooperation with other countries. On the one hand this leads to import of increased robustness, on the other hand to import of problems like outages and capacity shortage.

The report from the Norwegian Defence Research Establishment “**The Norwegian Electric Power System – system description and future development**” [23] presents a description of the

present Norwegian electric power system, as well as a discussion of emerging trends and future developments in this system. The report provides the basis for FFI's vulnerability analysis of the electric power system. The report states that Norway's electric power system is getting increasingly complex, due to a large-scale implementation of electronic components and information systems. Workforce reductions and efficiency improvements dominate the development of the electric power sector. Norway is also becoming increasingly dependent on foreign power sources. These trends provide for an entirely different electric power system than just a few years ago. According to the report, these trends make it virtually impossible to present a "static" description of the system. Thus, the report also contains a scenario, describing possible future developments of the system until 2010.

Some specific issues that are presently increasing the system's vulnerability are identified:

- The dependency on critical competence. In the short term reduced staff may increase vulnerability, especially the reduced number of people with strong knowledge of local circumstances, which the report characterizes as special competence. The number of people on duty outside working hours is being reduced, and in a critical situation it will take longer time to find people with the right competence. In the longer term, when the present generation retires, the availability of people with the necessary competence within electrical power may well become a problematic factor.
- Reduction and partly vanishing of a national supply industry for power components, and the reduction of the number of components in store.
- The dependency of other functions in society, specifically telecommunications and IT. In some contexts, there is full redundancy because one has been aware this dependency. In others, there is not. As an example the report mentions communication with staff, and the tendency that mobile telephone networks are dependent on power and tend to get overload in special circumstances.
- Dependency on other countries. Different regulations can have the result that the resulting level of preparedness becomes too low. One of the questions that can arise is reduction of national demand to support other countries' needs, and this necessitates bilateral agreements.

The scenario analysis "**Sweden stops without electricity**" [24] analyzes 7 different scenarios that could threaten the Swedish society. One of these is large, long-lasting power outages. Three sub-scenarios are defined:

- Storm and cold weather in Southern and Western Sweden
- Sabotage of the main grid during a cold period
- 19 weeks closure of all nuclear power because of a software error

The scenarios are illustrated by looking at the kind of problems that occur in three selected municipalities, among them Gothenburg. Problems on a number of areas are described:

- Traffic and telecommunications
- Hospitals
- Retailing
- Industry
- Water supply and sewage systems



- Agriculture
- Room heating and especially problems for the elderly
- Problems in distribution of petrol
- Burglary

The descriptions are credible and give a good illustration of the problems of prolonged power outages. The first scenario has the worst impacts on normal life, because this is a total blackout for 3-5 days in a period with very low temperatures. There is some similarity between the description of this scenario and the actual experiences from the Canadian ice storm, see below. In the other scenarios there is power available, but it has to be curtailed in various ways. A similar situation might occur if physical curtailment would be used in a period of severe inflow shortage in the hydro system. For the scenario with the 19-week closure of all nuclear units it is concluded that this would be handled without physical curtailment in a normal hydrological year, though power cuts during high demand on cold winter days might be necessary. If this should occur in a dry year, considerable curtailment would be necessary. There is no doubt that the situation is worse today than in 1995, when the report was written.

The two final chapters describe a systematic analysis of the problems that occur and proposals for improved preparedness respectively. The focus is on how the *consequences* of extreme outages can be reduced.

The relevance of the analysis lies primarily in the documentation of consequences. Focus is not on the economic impact, but on the difficulties that arise in normal life and how they can be reduced. Implicitly it is clear that such incidents are unacceptable, and that they cannot be the subject of economic optimization. On the other hand, it is also unavoidable that such incidents occur, and society must be prepared to minimize the consequences.

In "**The Canadian ice storm**" [25], the Swedish Agency for Civil Emergency Planning presents the results of a study of the Canadian ice storm in 1998. In this incident, severe icing destroyed major parts of the transmission system in Quebec. Initially 1.6 million people were without electricity. Supply was slowly restored, and 90 % of the consumers got back their power within two weeks. It took up to four weeks before all consumers were reconnected. Maximum disconnected capacity was 8000 MW, and total energy not served probably a little below 1 TWh (our estimate).

Naturally, the situation became critical for elderly, sick and handicapped people. The cold climate made it difficult to keep buildings warm, and only a minor share has alternative heating sources. Many people had to leave their homes, businesses had to close and basic services stopped. The situation was life threatening for people and animals. It is estimated that 34 people died as a consequence of the ice storm.

The situation was worst on the countryside. One of the reasons was that two thirds of the population there also lost telecommunications, while this happened for only one sixth of the urban population. Many people did not have battery radios or mobile phones. The results were that it was impossible to get information through to a large number of people.

The Canadian GDP was reduced with 0.7 % in January 1998, but the impact was severe for certain geographical areas and industries like dairies and maple syrup.

“**The Auckland power outage**” [26] is a description by the Swedish Agency for Civil Emergency Planning of a major power outage in Auckland, New Zealand in February 1998. In this case a series of power cable failures resulted in the outage of the Central Business District in Auckland for five weeks. Peak demand in the area was about 150 MW. Energy not served can roughly be estimated to 60 GWh. In terms of MW affected this was a relatively small outage, but it hit an economically important area and it lasted a long time.

The reports points at the following effects on human health and safety:

- Increased risk of fire caused by improvised solutions for reserve power
- Damage to the city environment due to emissions from reserve generators
- Large increase of the transport of dangerous goods (petrol) through the whole area
- Temporary and insecure power supply
- Increased risk of legionnaires' disease due to reduced water flow in the water supply system

Afterwards it appeared that there had been no deaths, major accidents or cases of illness. There were relatively few households in this business area. Generally the effects of the outage were limited due to the many actions that were taken. In this case, a large number of reserve generators from within and without New Zealand were transported to Auckland. Many of the (financial) companies in the area moved out temporary, but the situation was worse for retail businesses and restaurants.

The report hypothesizes that one reason that for the long duration of the outage may have been that fact that the responsible company Mercury did not by itself have the necessary competence and resources for diagnosing and repairing the cables.

### 3 THE VULNERABILITY OF THE NORDIC POWER SYSTEM

Appendices 1, 2 and 3 describe analyses of the vulnerability of the Nordic power system with respect to energy shortage, shortage of generation capacity and power system failures resulting in blackouts. The basis for the analyses is the methodology developed in Chapter 2. This Chapter summarizes the analyses in the appendices.

#### 3.1 ENERGY SHORTAGE

Analysis of energy shortage is carried out with the EMPS model (cf. Appendix 5). The main uncertainty with respect to energy availability in the Nordic power system is the variation in hydro inflow to the reservoirs, represented by historical inflow statistics for the years 1931-2000. Total inflow to the present Nordic system varies between 144 TWh (historical inflow year 1969) and 264 TWh (historical inflow year 2000), a variation of 120 TWh, amounting to 30 % of annual Nordic consumption. As discussed in Section 2.4.1, the criterion for classification of energy shortage is loss to Nordic consumers, compared with situations with normal prices. This loss is calculated by multiplying the difference between simulated weekly spot prices and the average weekly spot price with weekly electricity consumption.

Table 3-1 gives an overview over the scenarios that are analyzed with respect to energy shortage. The scenarios are discussed in some more depth in Appendix 1.

Table 3-1: Overview over scenarios in the energy shortage analysis

Year	Scenario	Description
2005	main	Existing system
2005	cable failure	500 MW cable Norway-Denmark out for 5 months
2005	nuclear failure	1160 MW Oskarshamn 3 out for 3 months
2010	most likely	balanced development, demand growth met by corresponding growth in generation capacity
2010	2010-1	No gas plants in Norway
2010	2010-2	Continued operation of Barsebäck 2

For the present system, Figure 3-1 shows the simulated loss to Nordic consumers for all historical inflow alternatives, together with the borders between the classifications derived in Section 2.4.1. For comparison, the calculated loss to Nordic consumers in 2003 was 4.8 billion Euros.

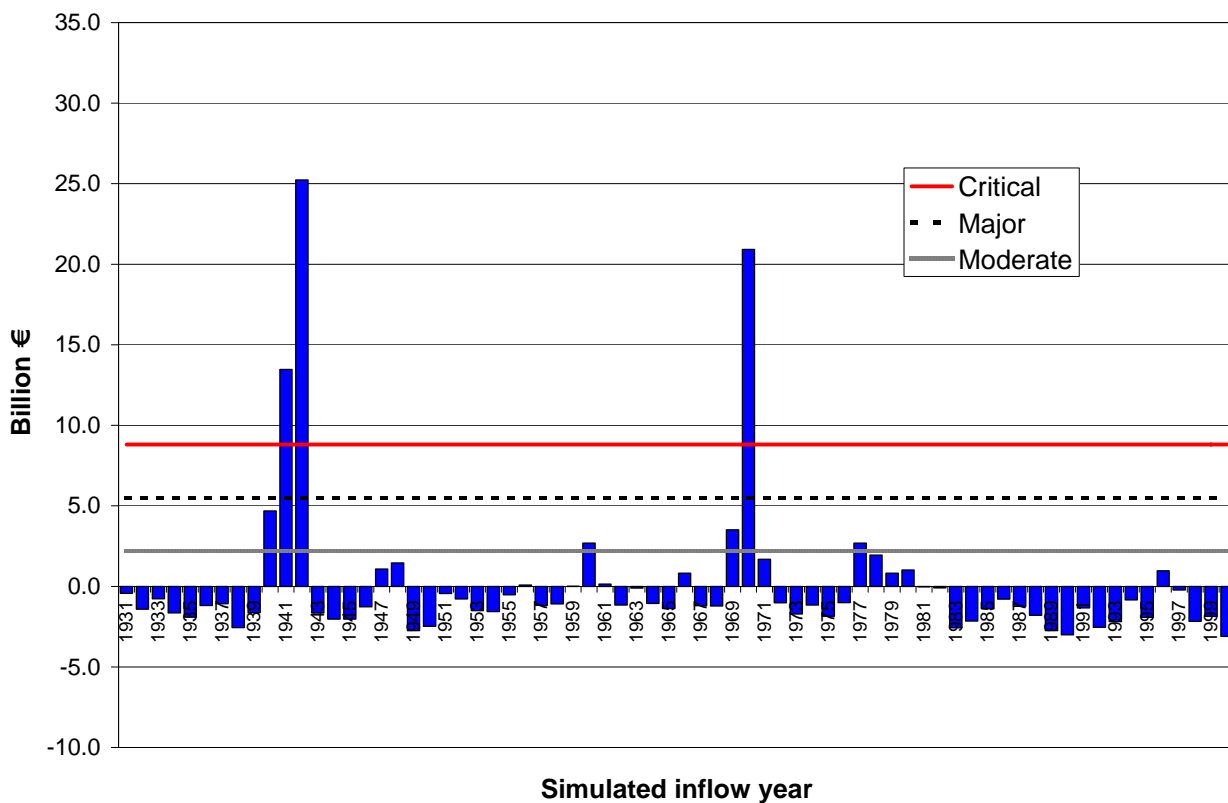


Figure 3-1: Consumer loss caused by high prices, present system

Three of the scenarios result in physical curtailment with the modelling assumptions used. What would happen in reality is hard to predict because the elasticity of demand during very high prices (in the range of 100 to 400 €/MWh) is unknown, and because it is uncertain how the authorities would react on prolonged periods of such prices. Norway is most vulnerable for high prices and possibly curtailment due to energy shortage because of its high dependence on hydro power, but prices will be almost as high in the other countries as well. In the simulations also Sweden and Finland experience some curtailment.

Based on these simulations the number of scenarios characterized as “unwanted events” are:

Scenarios	Number of outcomes	Probability
Moderate or worse consequences	7	10 %
Major or worse consequences	3	4 %
Critical consequences	3	4 %

For 2005 two additional scenarios were analyzed. In one of these, 500 MW of cable capacity between Denmark and Norway was assumed out of service for 5 months, in the other the 1160 MW Oskarshamn 3 unit was assumed out of service for 3 months. The results of these simulations naturally show that consumer losses increase, but the impact is relatively small compared with the

effect of extremely low inflow periods. In the context of vulnerability as defined in this study, such long term outages in the present system do not change the situation dramatically, but the number of “Major or worse consequences” increases from 3 to 4. Consumer losses will increase with 1 to 1.5 billion Euros in the driest years, although this does not show in the classification.

For the analysis of future vulnerability for energy shortage in 2010, three scenarios were used. The most likely scenario has a balanced development of supply and demand, resulting in a vulnerability very similar to the present system. The number of years in each class of unwanted events is almost equal, but with slightly more curtailment in the critical years. To assess an “under balanced” situation, a scenario without 800 MW of gas plants in Norway was defined, while a situation with more supply was simulated by assuming that Barsebäck 2 was not decommissioned. Figure 3-2 shows consumer losses in the case without gas plants in Norway.

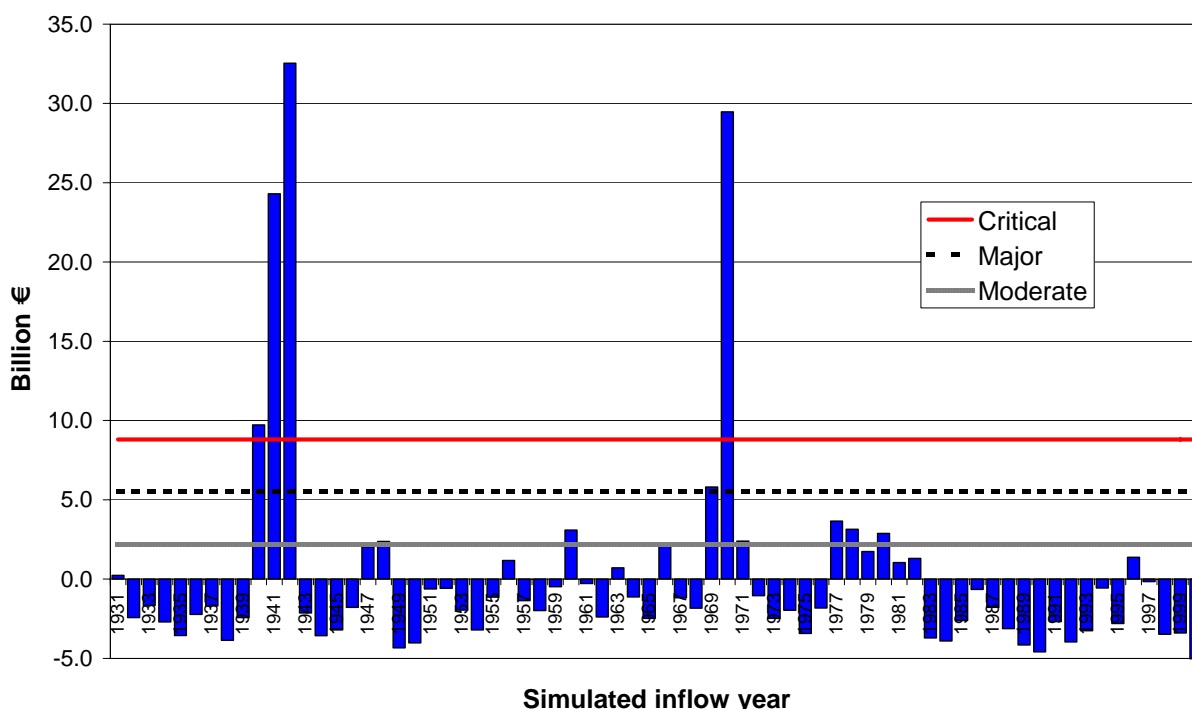


Figure 3-2: Consumer loss caused by high prices, future system, no gas plants in Norway

A similar situation can also occur in the case of delay of the commissioning of the 1600 MW Oikiluoto 3 nuclear power plant in Finland.

For this case the occurrence of “unwanted events” is:

Scenarios	Number of outcomes	Probability
Moderate or worse consequences	12	17 %
Major or worse consequences	5	7 %
Critical consequences	4	6 %

Roughly speaking, price increases like in 2002/03 *or* worse would be seen every 6 years.

A permanent state of under balance like simulated in this scenario leads to considerably higher prices on average. Probably this would suppress demand, resulting in less severe effects of inflow deficits and a reduction in vulnerability.

Figure 3-3 shows the energy shortage risk graph for the present and future system.

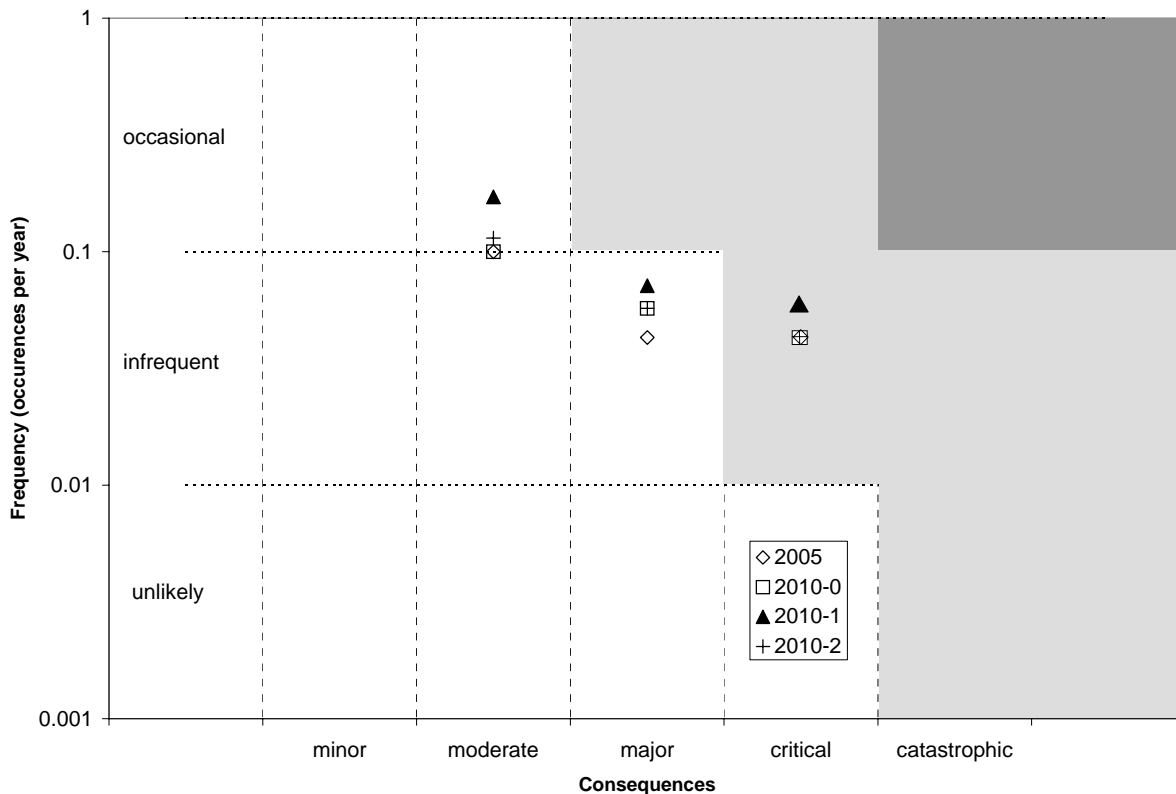


Figure 3-3: Risk graph energy shortage (2010-0: most likely, 2010-1: no gas plant in Norway, 2010-2: continued operation of Barsebäck 2)

The risk graph shows a medium risk state, caused by the significant consequences of extremely dry years.

Uncertainty in these calculations is primarily related to two issues: demand elasticity and model philosophy. As already mentioned, demand elasticity at very high prices may be underestimated. It is difficult to know this elasticity because very high prices over a sustained period have not occurred. An underestimation of demand elasticity implies that real prices during critical events are lower than the model estimates, and this reduces the highest outcomes in Figure 3-1 and Figure 3-2. We do not believe that this would reduce the *number* of critical events, because prices would have to be very high to trigger this price elasticity. The model philosophy assumes that the system is run from a single-owner optimization point of view. This probably results in a better utilization of resources than obtained in the real interplay of independent market participants. As a result, the model may obtain a more favourable energy balance and lower prices than is seen in the real

world. The result of this may be a certain underestimation of the number of unwanted high-price events.

Another type of uncertainty lies in the possibility that the EU Water Framework Directive 2000/60/EC will reduce hydro generation in the Nordic countries, but if this will be the case and what the size of the reduction would be is impossible to know presently. Implementation of the Directive is planned between 2010 and 2012.

### 3.2 CAPACITY SHORTAGE

In the context of the present study, capacity shortage is defined as a situation where available generation capacity and imports together are insufficient to serve demand without violating the constraints of the grid, while keeping satisfactory reserve levels. A capacity shortage may show either in the spot market or in real time or both. A capacity shortage in the spot market manifests itself by the fact that the supply and demand curves do not intersect, and there is neither a defined market price nor a clearing volume. A capacity shortage situation may alternatively occur in real time, either because demand becomes higher than expected or because of outages of generation or transmission in an already stressed situation. If the list of available objects in the Balancing Market is exhausted, there is a situation where severe frequency deviations and grid overload may occur.

There is a certain ambiguity between a capacity shortage in the spot market and in the Balancing Market. If a capacity shortage occurs in the spot market, it can be avoided by using capacity reserved for the Balancing Market, but this will transfer the problem to the Balancing Market – and make it the responsibility of the TSOs, while security of supply is reduced. If a capacity shortage will show in the spot market, and ultimately if it will result in curtailment of load, depends partly on how low the TSOs are willing to let reserve levels drop before taking action.

The analysis of generation capacity shortage focuses on peak demand on three different types of winter days: a normal winter day with a recurrence interval of two years, a cold winter day with a recurrence interval of ten years and an extreme winter day with a recurrence interval of thirty years. Demand estimates are based on Nordel data and on other available forecasts. For the generation system, expected availability on a cold winter day is used.

With respect to *vulnerability*, the important issue is what happens under special conditions, and what kind of special conditions can lead to situations with serious consequences. Special conditions occur when generation availability is reduced or when import availability is less than expected. We therefore consider several scenarios to represent these situations. Three different scenarios are considered:

- reduced import availability
- reduced availability of hydro generation
- outage of one nuclear unit

In the context of vulnerability, the main concern is involuntary shedding of load or blackout. In a situation where generation capacity is insufficient to supply demand, it is important to consider demand elasticity and the utilization of reserves. Elasticity of demand in Elspot effectively reduces peak demand. Paying demand for being available in the Balancing Market is a way of ensuring demand elasticity in real time. If all demand flexibility is exhausted and generation is still insufficient, reserve requirements must be considered. By reducing reserves, involuntary curtailment can be avoided, but at the cost of increased probability of blackouts.

Several scenarios have been analyzed, cf. Appendix A2.2. The most realistic of these is the scenario where it is assumed that there are roughly 2000 MW demand side reserves available for the TSOs, which is comparable to the present situation<sup>10</sup>. This means that *generation* reserves can drop to approximately 2000 MW, while keeping a total amount of reserves corresponding to the Nordel requirements. 2000 MW of generation reserves is well above the Nordel limit of 600 MW, but implicitly takes into account that this would be a critical situation with respect to system security, even though curtailment is avoided. Under these assumptions, the system is basically in a low risk state, although the probability of critical consequences is slightly too high (once every 70 years). This situation occurs in the case of extreme demand, combined with low import capability and/or reduced hydro and nuclear availability.

We now discuss in some more detail the results for this scenario, assumed to be most realistic in terms of the capacity balance. A *normal winter peak* will have a positive capacity balance for all outcomes, also with reduced imports, low hydro availability and one nuclear unit out of operation. On balance, there is no need for import to the Nordic area for any of the outcomes.

In the case of a *cold winter*, the Nordic countries have a need for imports exceeding the assumed realistic import capability of 2500 MW in the case of low hydro availability. With reduced availability of import, this capability will even be exceeded with normal hydro availability together with unavailability of one nuclear unit. However, the need for import never exceeds *physical* import availability. The worst case has an expected Nordic deficit of almost 2100 MW, an average curtailment time of 8.8 hours and 18 GWh of energy not served, representing moderate consequences. Curtailment will primarily have to take place in Sweden and Finland, and possibly to some extent in Norway.

In the case of an *extreme winter*, the need for import to the Nordic countries exceeds assumed realistic import for all outcomes. Unless normal availability of hydro, the need for import will exceed physical import capability. The worst case scenario has a Nordic deficit of 4000 MW, an average curtailment duration of 15.5 hours and an estimated energy not served of 62 GWh. The probability of this scenario is however extremely small. Consequences fall in the minor or moderate classes for all outcomes.

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<sup>10</sup> In Appendix 2 this scenario assumes that there are no demand side reserves but that 50 % of the fast reserves can be used before load is curtailed. This results in roughly the same capacity balance, but using 50 % of the fast reserves would significantly reduce system security. The interpretation of this scenario assuming demand side reserves is better adapted to the present development.



The risk situation for capacity shortage deteriorates between 2005 and 2010. The probability of the spot market failing to clear is estimated to 0.22 in 2010, between once every four and once every five years.

Looking at the same scenario, the probability of minor and moderate consequences is still within the occasional range, but the probability of major consequences also comes in this area. The probability of critical consequences is now estimated to once every 17 years. The main reason for the severity of the consequences is the flat daytime demand profile in the Nordic countries. This implies that when there is a shortage of several thousand MW, this will involve many hours of load shedding and a correspondingly high level of curtailed energy. As for the analysis of the present system, demand elasticity is probably underestimated, improving the real situation to some extent.

Under the assumption of the most representative scenario, a *normal winter peak* will have a positive capacity balance for all outcomes also in 2010. Sweden and Finland have a negative balance, while Norway and Denmark have a positive balance for all outcomes.

In the case of a *cold winter peak*, the need for import to the Nordic area exceeds assumed realistic import for all outcomes. The deficit is about 200 MW for the most favourable outcome, increasing to 4300 MW in the worst case, which results in a curtailment of 3700 MW with an average duration of 14.3 hours and energy not served of 53 GWh, which is still a moderate curtailment case according to our classification. For the other outcomes the consequences are minor or moderate.

An *extreme winter peak* would be problematic in 2010. For all outcomes the need for import would exceed physical import capacity. Worst-case curtailment is 5600 MW with an average duration of 18.4 hours and energy not served of 102 GWh, which is classified as a major consequence. Also several of the other outcomes have major consequences, while the remaining have moderate consequences. Still, the probability of such outcomes is quite low also in 2010.

The deterioration of the capacity balance between 2005 and 2010 is caused by the fact that the major share of new resources (gas, nuclear, wind) consist of base load options, contributing less to peak generation than to energy supply.

Concluding, the vulnerability of the Nordic power system is in the medium risk area, and actions should be evaluated to reduce the risk.

Figure 3-4 shows the risk graph for capacity shortage.

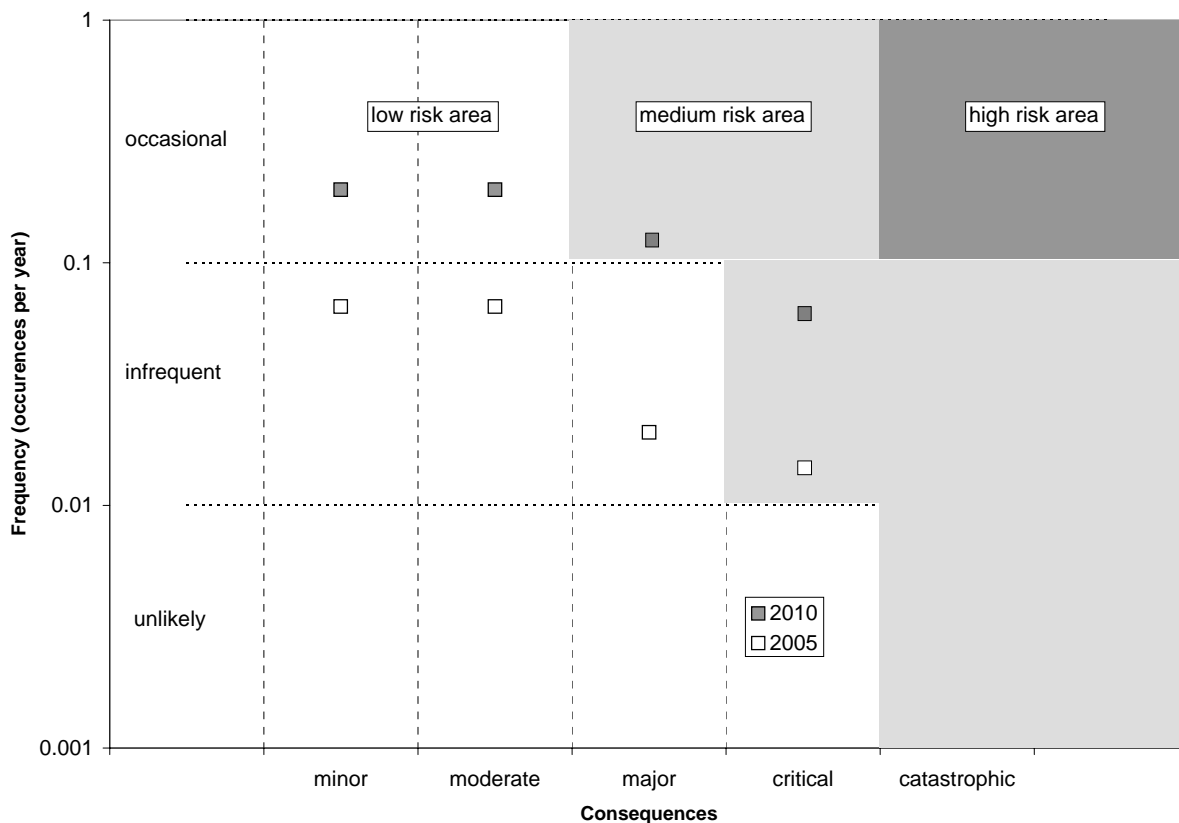


Figure 3-4: Risk graph capacity shortage

### 3.3 POWER SYSTEM FAILURES

The risk of power system failures depends on the probability of the combination of faults and disturbances that lead to a system collapse and the consequence of the interruption in terms of power and energy not supplied, duration of the outage and other factors such as serious damage or injuries caused by the blackout.

#### *Probability*

Failures and disturbances in the power system can never be completely avoided. Still, the probability of critical blackouts is low. This is closely related to the way the system is designed and the operating security criteria that are applied.

The two main factors that influence the probability of power system blackouts are the failure rates of components and the operation of the power system:

- High focus on cost reduction has an impact on the level and quality of maintenance work. In combination with the fact that power system components grow older (as a result of lower investment rates), this contributes to increase failure rates.
- Stronger and more frequent variations in power flow patterns increase the number of hours with congestions on critical corridors. This increases the probability of critical failures developing into a blackout.

The probabilities of blackout scenarios are expressed as frequencies and ranked according to how often the situations are assumed to occur, as shown in Chapter 2.5. The probability of occurrence of each scenario is quantified as far as possible based on the chains of causes described by the blackout event tree of Chapter 2.2. The quantification is based on sources such as disturbance and fault statistics from the Nordic countries (Nordel) when available. Otherwise, it is based on experiences and expert evaluations (qualitative judgements).

### ***Geographical areas***

Due to the regional and national differences in structure of the power system as well as the location of generation, the impact of electricity supply deficiencies varies in different areas or parts of the Nordic countries. The consequence evaluation is therefore carried out for different geographical areas, determined by the topology, transmission capacities, bottlenecks etc. The areas chosen are as follows:

- 1) Finland, import case
- 2) Finland, export case
- 3) Helsinki area
- 4) Northern Sweden
- 5) Southern Sweden
- 6) Gothenburg area
- 7) Stockholm area
- 8) Eastern Denmark and Copenhagen
- 9) Western Denmark
- 10) Southern Norway and Oslo
- 11) Western Norway and Bergen area
- 12) Stavanger area
- 13) Southern Scandinavia

The following figure shows the results for the present system:

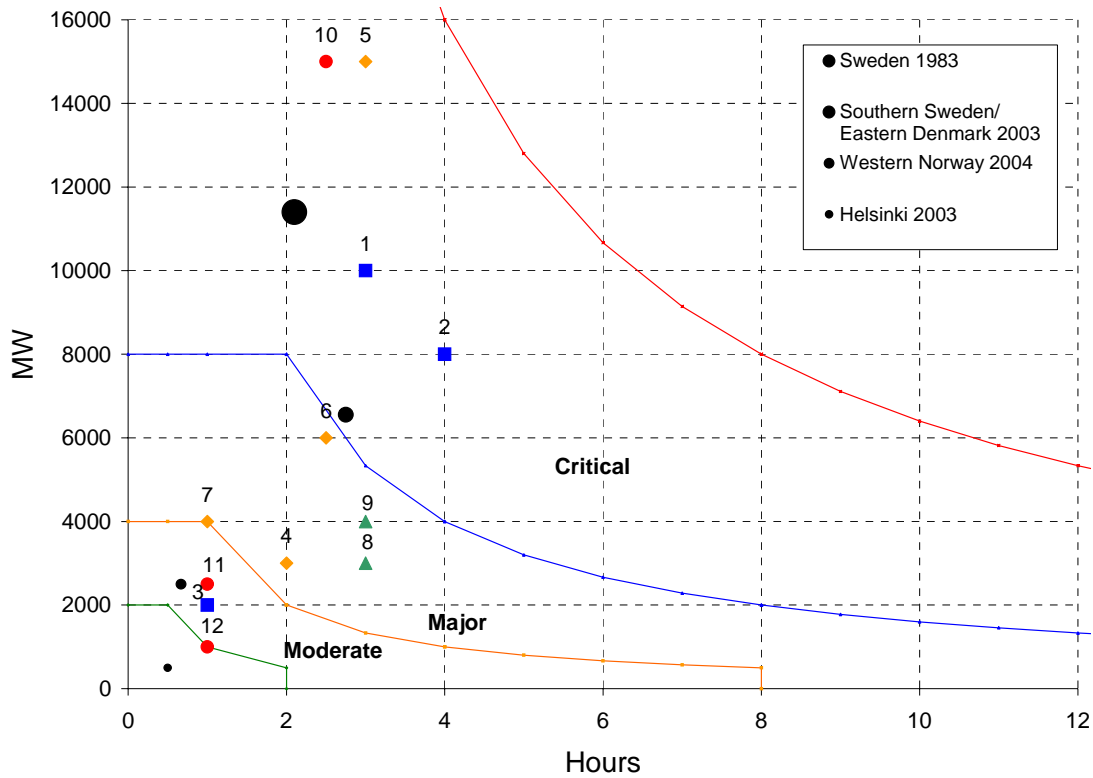


Figure 3.5: Consequence assessment of present system. The numbers refer to the areas given above. Blue coloured markers (squares) are used for the Finnish scenarios, orange colours (diamonds) for Sweden, green (triangles) for Denmark and red (circles) for Norway. Some historic blackouts are also shown.

Figure 3.6 shows the corresponding risk graph.

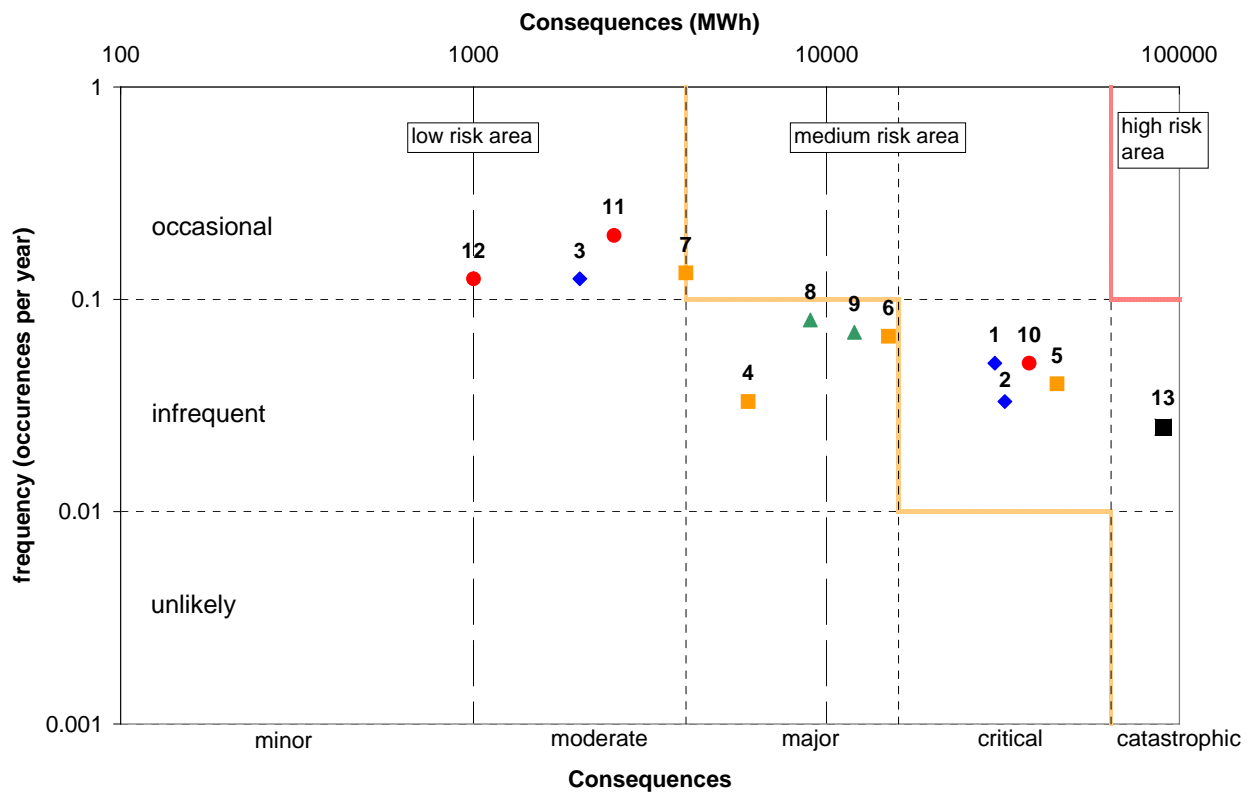


Figure 3.6: Risk analysis for the present system. The numbers refer to the scenarios described above.

There are five scenarios that can be characterized as critical or worse. All these events are likely to happen infrequently, i.e. with frequency of occurrence less than one per 10 years. Thus, they come in the category *medium risk*. All other scenarios are low risk and will not be further commented.

It is noted that all the scenarios in this category involve the blackout of either Southern Norway, Southern Sweden or Southern Finland or a combination. This is mainly due to high load concentration in these areas, and not that the reliability of the power system here is lower than in other parts of the system in any way. Moreover, the critical scenarios assume operating conditions with high power exchange (import to or export from) the area, suggesting that it is the imbalance between local generation and load that first of all causes the critical situations. With the exception of the scenario with high import to Finland, the analysis suggests that the most critical situations arise in operating conditions with very high power transfer from east to west or from north to south.

With respect to the future system towards 2010, we do not find obvious reasons to expect significant changes in the risk of blackouts. The main factors and developments that could adversely influence the probability and consequences of power system failures are summarized below:

- Uncertainty is related to how the probability of blackouts changes as the power system and the operating conditions change in the future. One reason for this can be the location of new gen-

eration resources, which has become less predictable than previously because of a lack of integrated planning of generation and transmission. New generation capacity and changes in the mix of generation can lead to occasional power flow patterns with higher risk. If the frequency of bottlenecks due to very high demand for power transfers from east to west and from north to south increase in the future, this will be of particular concern.

- High focus on cost reductions and possible changes in maintenance routines are factors that increase the probability of failures. The fact that investments in the transmission grid have been low during the last decade could increase failure rates as the components in the power system grow older. In the long run, reduced maintenance will also contribute to increase failure rates. On the other hand, it is also a fact that maintenance work in itself is a factor that tends to increase the probability of failures. The total consequence of this is therefore somewhat uncertain.
- Competence and education of power system engineers are of paramount importance. Lack of staff with necessary technical competence within power system operation, planning and maintenance is a possible threat to future risk of power system failures.

The analysis identifies a few scenarios as *medium risk* events, indicating that some form of actions should be considered. The critical scenarios involve blackouts of Southern Finland, Southern Sweden or Southern Norway. These are events with very low probability, and thus the actions should be targeted towards limiting the consequences. This can only be achieved by early detection and mitigation of initiating faults, by limiting the amount of power that is interrupted and by minimising the duration of the outage.

Possible solutions and actions to achieve this goal are:

- Development of methods, tools and skills that enable fast detection of failures and critical operating conditions.
- Fast control actions to prevent cascading outages that would lead to a blackout. This can be operator actions or automatic control systems.
- System protection solutions to prevent or minimize spreading of the blackout to larger areas.
- Better training and preparedness to enable fast restoration after a blackout.

These are all actions that will benefit from a close coordination and cooperation among the Nordic TSOs. The actions require focus on operator training and education, improvements in operation planning and control centre applications. R&D work with industry involvement is needed to develop new monitoring and control solutions.

## **4 CHALLENGES IN HANDLING VULNERABILITY IN A NORDIC CONTEXT**

The analysis so far in this report has presented a broad picture of the present and expected future vulnerability of the Nordic power system. With respect to energy shortage there is concern regarding very dry years and their impact on hydro generation, especially in Norway. With respect to shortage of generation capacity during peak demand, the present situation is generally satisfactory. To a considerable extent this is the result of actions already taken by the TSOs. Towards 2010 the balance will probably weaken somewhat, but the risk level will probably still be acceptable with the assumptions that were used. Vulnerability for power system failures is in the medium risk area, both presently and in the future. This is a result of the consequences of large blackouts in the Southern parts of Finland, Sweden and Norway with a probability of occurrence of once every 10-20 years.

Before presenting a proposal of actions in Chapter 5, the present Chapter gives a short overview of relevant aspect of the institutional framework for the Nordic power market. For completeness, the first Section shortly introduces the major institutions, probably well known to most readers. Subsequently, the relation between certain institutional differences and vulnerability is discussed.

### **4.1 MAJOR INSTITUTIONS**

#### **The Nordic Power Exchange (Nord Pool)**

Nord Pool was established in 1993 as an exchange for the Norwegian electricity market only. In 1996 the exchange was extended to include both Norway and Sweden, and thus became the world's first multinational exchange for trade in electric power contracts. In 2002 Nord Pool was reorganized into three different entities. Nord Pool organizes the financial trade, Nordic Electricity Clearing House is responsible for the clearing of both the financial and the physical market, both operating under the Norwegian Exchange Act supervised by BISC (Norwegian Banking, Insurance and Securities Commission), and Nord Pool Spot organizes the physical trade under the Norwegian Energy Act supervised by The Norwegian Water Resources and Energy Directorate. As an exchange, Nord Pool is not directly involved in the physical system operation. Still, the confidence in Nord Pool as an exchange and the credibility of the spot prices and derivatives are crucial for the development of the market, and thus for the vulnerability of the system in the long term.

#### **The Nordic TSOs**

The five TSOs in the Nordic area<sup>11</sup> are owners of the respective national main grid and responsible for co-ordination between producers, consumers and other network owners.

They cooperate according to the recommendations from the Nordel organization. The five TSOs have signed a System Operation agreement which contains following aspects: reliability, opera-

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<sup>11</sup> The Danish TSOs Eltra and Elkraft System will be merged into one state-owned company EnergiNet Danmark as of 1 January 2005.

tion limits, outage coordination, ancillary services, congestion management, emergency operation, balance operation, power exchange, settlement and exchange of information.

With regard to market operation the main tasks carried out by the TSOs are: Definition of available transmission capability (ATC) between the price areas, load/frequency balancing, and congestion management. The main principle for calculation of ATC is the N-1 criterion. This requires that the transmission system must be able to restore stable conditions in the system in case of failure on any one component of the system.

### **The Nordic regulators**

There are separate regulatory authorities in the Nordic countries controlling the monopoly functions like Network Owners and System Operator responsibilities. The Nordic regulators are:

Denmark	Energitilsynet, the Energy Market Inspection
Finland	Energiamarkkinavirasto, the Energy Market Authority (EMV)
Norway	Norges Vassdrags- og Energidirektorat, the Norwegian Water Resources and Energy Directorate (NVE)
Sweden	Statens Energimyndighet, the Swedish Energy Agency (STEM)

## **4.2 INSTITUTIONAL FACTORS AND VULNERABILITY**

In the context of the present study, vulnerability is related to extreme price-situations, load curtailment, and blackout in the power-system. An important issue is whether, and in case to what extent the vulnerability is influenced by the actions of and cooperation between the respective major institutions mentioned in the previous Section. This is illustrated on the left side of the event trees in Chapter 3, where arrows indicate relations between on the basic events in the event tree and:

- Power market development
- Nordic TSO co-operation
- Nordic regulatory framework

“Power market development” is the general development of demand and supply in the power market, influenced of economic cycles, demographic development, expectations etc. This is outside the *direct* influence of the institutions, but will to some extent be influenced by their actions.

In the following Sections, we will evaluate how actions and regulation applied by the major institutions may influence certain aspects of power system vulnerability.



#### **4.2.1 Investment in transmission**

Over time, investments in new transmission capacity are necessary to maintain a transmission grid that is optimally adapted to the requirements of the power market. When it comes to investment in transmission, the regulatory frameworks under which the TSOs are operating are of vital importance.

According to Chapter 4 in the Danish regulation for the TSO<sup>12</sup> [46], the TSO shall carry out a coherent, comprehensive planning, which shall form the basis for an evaluation of, among others, security of supply (§11). The planning horizon shall be 10 years. The planning of the grid over 100 kV and of the interconnections with areas controlled by other system operators shall be done according to dimensioning criteria agreed upon with the Danish Energy Authority (§12). The TSO's organization and the transmission system organization shall together apply for approval by the Danish Energy Authority of transmission system expansion and upgrading (§14). Congestion within the Danish system is relieved with counter trade, resulting in a cost for the TSO.

In Finland, the supervision on Finnish electricity market and on pricing and terms of network services is based on ex-post regulation. It means that the network companies set the tariffs and terms of network services by themselves – pre-acceptance from the Energy Market Authority is not required. The Energy Market Authority supervises the tariffs and terms afterwards on a case-by-case basis (EMV web site). Congestion in Elspot within the Finnish system is relieved with counter trade.

In Norway, regulation of the TSO is given in the “Regulation on economic and technical reporting, revenue caps for grid companies and tariffs” [47]. The most relevant chapter in the present context is Chapter 11, dealing with the annual revenue cap for the “system responsible grid company”. According to §11.1, the TSO is regulated with a total revenue cap that includes cost related to its own grid and costs related to the system operator role. Where relevant, general rules for grid companies given in other chapters apply. Subsequently rules for how costs are calculated are given, as well as a number of circumstances where the revenue cap can be adjusted. For new lines or upgrading of existing lines, the TSO shall apply to NVE for concession. The general “KILE” arrangement (Norwegian acronym for “Quality adjusted Revenue caps for Energy not Served”) also applies to the Norwegian TSO. This implies that the revenue cap of the TSO in the case of outages in the main grid is reduced with an amount corresponding to the energy not served multiplied with an estimated value of lost load. Congestion in the Elspot phase in the Norwegian system is relieved with market splitting, resulting in a revenue for the TSO. However, this revenue is compensated through a reduction of the next year's revenue cap, so congestion is revenue-neutral for the TSO.

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<sup>12</sup> Both the Danish and the Norwegian use the term “systemansvarlig”, meaning “the organization that is responsible for the system”. There is no adequate direct short translation for the Danish/Norwegian word, and because this role in practice is played by the TSO, we use the latter instead of the long paraphrase.

In Sweden, the basis for the regulation of the grid companies is given in Chapter 4 of the Energy Law, where §1 states that grid tariffs shall be such that the grid concessionary's total revenues from its grid related activities are fair in relation to their operating conditions for these grid activities, partly the grid concessionary's way to carry out these activities. According to §9, the judgment of the fairness of grid tariffs for voltages above 220 kV shall take into account the calculated cost for the concessionary's way to operate the total grid at and above this voltage level. The Energy Authority supervises the grid companies in Sweden. Among its tasks is the judgment of the fairness of grid tariffs (STEM web site). Congestion in Elspot within the Swedish system is relieved with counter trade. More detailed regulations are given by annual Regulation Letters ("Regleringsbrev") from the Government. A Regulation Letter describes in considerable degree of detail what Svenska Kraftnät should do within a number of areas, and to some extent how they should do this. In this context, it should be noted that the full name of Svenska Kraftnät is "A-färsverket Svenska Kraftnät", meaning the Public Utility. In Sweden, the TSO is to a much stronger degree than in Norway seen as part of the authorities. Svenska Kraftnät decides on investments that can be justified from technical and socio-economic aspects within a three-year financial framework approved by the government.

It appears that regulation of the TSOs is very different in the Nordic countries. Norway has a formal revenue cap regulation, where the incentives of Statnett in principle are given through the economic impact of decisions on the company's economic result. Still Statnett has to apply for concession, and NVE will review an application and quite possibly deny concession when they find investment unprofitable for the society as a whole. In Denmark, investments in the main grid are explicitly subject to cooperation between the TSOs and the Energy Market Inspection. In Sweden and Finland investments in the main grid are more closely coordinated with the authorities.

#### **4.2.2 Balancing**

The TSOs are responsible for the balancing markets, which are used when imbalance occurs in the operational phase. The regulation objects for up and down regulation are used both in load frequency balancing and in "buy back" congestion management, which is described below. The response requirement for these "fast reserves" is 15 min. Although the TSOs in the Nordic system operate individually in the operational phase, there is close cooperation with regard to secondary frequency regulation, and from 2002 a common Nordic balance market was introduced.

Although the various balancing markets work well in handling imbalances during system operation, this clearly assumes that there are sufficient bids in these markets to handle conceivable imbalances. During periods with very high spot prices, it is more attractive for producers to sell power on the spot market, and the situation might occur where there are insufficient resources available for the balancing markets. The Nordic TSOs have chosen different solutions to cope with this potential scarcity of reserves [27].

Svenska Kraftnät has two different arrangements for fast reserves. The arrangements are not explicit on whether the reserves are reserves for the Balancing Market or Elspot, or both:

- Peak power capacity reserve – thermal capacity and demand reduction
- Fast reserves – gas turbines

*Peak power capacity reserve:* To strengthen the capacity balance, the Swedish government gave SvK the responsibility of purchasing 1400-1600 MW of capacity including both oil condensing and gas turbine, as well as demand side reductions if possible, for the period of January 2001 to March 2003. The cost of keeping this capacity reserve was distributed among the balance responsible market players. When SvK found need for this capacity it was bid into the Elspot market. The bidding price was two times the marginal cost. This model, with slight modifications, was prolonged by interim legislation until the winter of 2007/08, when it is hoped that a market-based solution can take over. The maximum amount of this reserve has been set as 2000 MW.

*Fast reserves:* SvK has at its disposal 1200 MW of gas turbines, of which 50 % is fully owned by SvK and the other half is leased on long-term contracts. This capacity is normally reserved for coping with sudden unforeseen disturbances (loss of line, loss of generation) in the power system. If the emergency or disturbance reserves have to be employed to avoid load curtailment in a capacity shortage situation they are presently priced to the level of 6000 SEK /MWh which also will be the price on balance power that is drawn from the Balance Service. The intention behind this is to clearly indicate that these reserves in principle are not available to the market. As an exception, in December 2002 and January 2003 SvK decided to bid this capacity into the Elspot market because of the critical energy balance in that period.

In Norway, Statnett has established a *Regulation Capacity Option Market (RCOM)*. As a starting point, Statnett assumes there is always 2000 MW available for upwards regulation. But in the winter period, from October to May, this might not be the case. In response to this and to ensure access to sufficient capacity during periods with high demand, Statnett collects bids and decide on the option volume in the middle of November. Then Statnett buys call-options (either from a producer or a consumer) that oblige the seller to submit offers in the Balance Market from 6 a.m. to 10 p.m. on weekdays. The length of these options is 1 or 3 months, with contract period lasting from 1 to 3 years. The decision criteria for which bids to accept are, among others, the option premium requested, the location, and the source (generation/consumption). The design of the RCOM is based on the fact that the potential bidders are basing their bids on hydro power plants, i.e. the relevant cost functions are quite different from cost functions in thermal power plants. The users of the high voltage grid cover the cost of the option market through the ordinary transmission tariffs. The cost varies from one year to another depending on the obtained volume and price.

Fingrid has had the responsibility for the regulation capacity market since 1st of January 1999, and as in Norway and Sweden it is voluntary to participate with bids. In Finland self-regulation is allowed to achieve a better balance. In addition to the voluntary participation in the Balancing Market Fingrid is using a special arrangement for long-term capacity reserves. To ensure the availability of sufficient fast reserves, Fingrid controls and maintains a total capacity of 672 MW gas turbines under long-term contracts. This capacity is arranged in the Fingrid's subsidiary Fin-

grid Varavoima Oy. The power from these plants is primarily used as fast reserves during disturbances, but some part of these resources can be made available to the Balance Market. If so, the capacity is remunerated with the highest price activated in the merit order list but at least the highest of the variable costs of the gas turbines and the Elspot price.

Elkraft System and Eltra have made agreements with the power producers Energi E2 and Elsam, respectively, on the supply of regulation capacity, provision of reserves, and a minimum capacity available. Most "local" purchases of balancing services in Denmark are made through these agreements, which were valid throughout 2003, and some elements in the agreement between Eltra and Elsam are valid throughout 2004. It is the avowed intention of both TSOs that on expiration of the present agreements, it shall be possible to purchase the services via more competitive agreements or mechanisms. Presently Eltra buys some reserves on the RCOM in Norway, cf. above.

The differences in the handling of the balancing markets can have detrimental effects on the long time ability to secure resources on market based conditions. We agree with SKM/COWI that especially subsidizing basic capacity that might eventually be used in the spot market should be avoided, with the possible exception of the case where the Elspot does not clear. In the latter case, prices should be very high and known in advance, to create a credible threat for market participants in case they cannot comply with their obligations.

#### **4.2.3 Curtailment**

Norway is the only of the Nordic countries that has legal provision for curtailment in the case of energy shortage, through regulations for power curtailment [15]. According to paragraph 4 in the regulations, the rationing authorities shall inform the ministry [of Oil and Energy] when there is a real risk that a rationing situation will occur. Effectuation and ending of rationing is decided by the ministry. Although not explicitly stated, it appears that the triggering event is a real risk for a rationing situation, and not high (or even extreme) prices. In the Norwegian Balancing Market, there is a price cap of two times the Elspot price, but at least 50000 NOK. In the Regulation for System Responsibility in the Power System [42], paragraph 13 states that "The system responsible can in very special situations instruct concessionaries to impose short coercive shedding of load", but there is no mentioning of price setting.

The Swedish Electricity Act authorizes the TSO to execute curtailment or load shedding in situations where it is necessary to sustain the system balance and integrity and no other resources are available. This is related primarily to instantaneous capacity shortages. A curtailment situation in the Balancing Market is also taken into account in the Balance Agreement of Svenska Kraftnät [43]. In the Section about Prices and Fees of the latter agreement it is stated under Paragraph 7 "Pricing of balance power in the case of capacity shortage" that the price for upward regulation is set to at least 6000 SEK/MWh when Svenska Kraftnät activates its disturbance reserves. In the extraordinary case that it is necessary to shed load, the price for upward regulation is set to 20000 SEK/MWh." The criterion for the high prices is that Svenska Kraftnät is "forced to shed load".

The Electricity Act does not have any provisions for rationing as an instrument to meet with energy shortages on a longer term basis.

Eltra's Memo on balance settlement and balance market [44] paragraph 4.2 defines "force majeure" situations, where security of supply is threatened by extensive disturbances, system breakdown, extreme weather or similar. In such cases Eltra can require the use of the total resources of the power system with the objective to reestablish normal system operation. Under such circumstances normal settlement rules in the balance market are suspended, and balance power is settled at the Elspot area price. This paragraph does not mention load curtailment explicitly, but it can be assumed that this is included in "the total resources of the power system" in extreme situations.

In Finland, the Section 7 of the Application Instruction for Balance Service [45] explicitly assesses the procedure during power shortage situations. A power shortage is deemed to have occurred when all available generation capacity in Finland is in use, all up-regulation bids have been activated and it is not possible to obtain additional electricity from the neighbouring countries. Moreover, in such a situation Fingrid must have activated its fast disturbance reserves. The price is set to the highest of the most recent up-regulation, the variable cost of gas turbine capacity used and the cost of other fast disturbance reserve used. If it is necessary to restrict consumption or disconnect loads involuntary, a serious power shortage occurs. The price setting rules are the same as for a power shortage.

Nordel's Power System Agreement states in Annex 9, paragraph 3.3: "When fast reserves are lower than 600 MW in the synchronous Nordic system, load without market based agreements is curtailed. Load shedding is effectuated in the system with the largest physical deficit compared with its balance. Load shedding is done gradually until the requirement of 600 MW fast reserves is satisfied". The next paragraph states that pricing shall be done according to normal principles, but it is clear that this can be problematic in such situations.

Thus, Norway has regulations for energy curtailment with a (vague) criterion for effectuation (real danger of rationing), but no explicit rules for pricing<sup>13</sup> in such cases. Sweden has an implicit mentioning of load shedding in the Balancing Market with explicit pricing rules. West-Denmark defines a force majeure situation, but this is only implicitly directed towards a generation capacity shortage that is not caused by major system disturbances. Fingrid clearly defines a power shortage, but pricing rules do not reflect the severity of the situation.

Clearly the pricing rules in the case of load curtailment differ substantially between the Nordic countries. It is not clear what happens with the exchange between countries if one country unilaterally interferes in the market and sets administrative prices.

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<sup>13</sup> According to the regulations, high prices are not a reason for curtailment. However, as we have argued in Chapter 5, we believe that curtailment may be effectuated if prices become extreme. Although it is stated that market based instruments shall be used as far as possible, we do not see how a market based price can be established realistically in the case of nation wide curtailment. A special case may be rationing in a limited area.

Because curtailment situations clearly affect the vulnerability of the Nordic power system, there is an evident need for harmonization in this area.

#### **4.2.4 Congestion Management**

The system price is the price that balances supply and demand for power in the whole spot market area in the absence of transmission congestion. The direction of power flow in the common Nordic power market is, in principle, defined by the location of generation resources and demand, and generators' and consumer's behaviour, related to their price expectations. Congestion is handled by a combination of price areas and counter trade.

Price areas are currently being used to handle bottlenecks between the Nordic countries in the Elspot phase. In Norway price areas are also used to handle internal bottlenecks. The use of price areas implies that the market is split in several areas with different prices. The prices are set in such a way that the flow between areas is within the limits set by the system operators.

Counter trade is used within Sweden, Finland and Denmark in the Elspot phase, and in all countries in real time. Counter trade implies that the system operator chooses specific options to regulate the power production on both sides of the bottleneck based on the price in the balancing market. This means that the system operator pays the producer to produce more/less on either side of the bottleneck in order to balance the overload.

The fact that congestion is handled in different ways within the same integrated market is in principle a disadvantage, which can lead to a sub optimal utilization of the total transmission and generation resources in the system. As such, it causes losses to all market participants and to society as a whole, compared with a unified way of handling transmission congestion. As a result, it is quite probable that prices on average are slightly higher than they could be, but to our belief the impact on average prices is marginal. Although a unified solution clearly would benefit the Nordic power market, it is hard to argue that the different procedures of congestion management will lead to substantially increased vulnerability.

#### **4.2.5 Export/Import limitation**

Power that is transferred into or out of the Nordic market area is administrated by different sets of rules than those governing rules within the Nordel area. As long as there is no real single integrated European power market with a common set of rules, this is a reality that must be faced. However, the rules that control the exchange between areas with different sets of rules should be as transparent as possible, securing an optimal exchange between such areas.

Trade on the Danish-German connections is currently conducted through bilateral agreements in addition to a daily capacity auction.

A few Nordic producers control the exchange between Sweden and Germany/Poland, something that is, or soon will be, in contradiction to EU regulations. The “Use-it-or-lose-it”-principle (UIOLI) is underlined as a guideline the EU Council. These principles are not implemented for the Swedish cables to Germany and Poland. Generally we are sceptical to the mixing of roles that occurs when generation owners also own parts of the transmission grid.

The import/export capacities to countries outside the Nordic area might, under present arrangements, be used in a way that worsen a conditions of energy shortage or scarcity of power in the Nordic countries, although we have no reason to believe that this has happened. In general, it is better to avoid such situations through a strict separation of ownership. A failure to do so may sooner or later have impacts on the vulnerability of the power system, leading to increased probabilities of high prices or curtailments.

### **4.3 SUMMARY OF CHALLENGES**

The previous Sections have briefly introduced several areas where differences between Nordic laws and regulations represent potential barriers for improving the vulnerability of the Nordic power system in a market efficient way:

- Regulation of the TSOs is significantly different between the countries. This, and the fact that decisions within each country primarily are taken from each country’s perspective, almost certainly leads to investments that are sub-optimal from a Nordic perspective.
- Lacking, diverging and to some extent contradictory rules with respect to curtailment and price setting during curtailment fail to give clear signals to the market players with respect to their position, should curtailment be unavoidable.
- Differences in the procurement of fast reserves lead to sub-optimal solutions from a Nordic perspective.
- Differences in congestion management constitute a market inefficiency. In the context of the present study these differences may also increase vulnerability by reducing export capacity, and in very special cases the probability of blackouts may be increased, but these are no major effects.
- Some connections between Sweden and continental Europe are owned by power producers. Although there is probably no reason that this has been any problem so far, this gives these produces increased market power with possible negative effects on the e.g. imports during periods of energy shortage.

In the next Chapter a number of actions will be proposed to reduce the vulnerability of the Nordic power system, or to avoid that the vulnerability will increase. A number of the proposed actions will assess the challenges indicated in Chapter 4.

## **5 PROPOSED ACTIONS**

In this final Chapter of the report, it is appropriate to remind of the scope of the study, which is limited to the vulnerability of the Nordic power system, as related to generation, demand and the main transmission grid. The vulnerability at the distribution grid level is outside the scope of the study. Although according to statistics the dominating share of demand interruptions is caused by faults at the distribution level, this is primarily a national concern in the individual countries. This said, available statistics do not show any increase in demand interruption so far, although there have been problems in both Norway and Sweden in the past winter with considerable focus from the media. With this in mind, it is important to point out that the Nordic power market generally has performed well. Although there have been some blackouts recently, the analyses in this report do not indicate that the vulnerability of the Nordic power system has become unacceptable, although especially the energy balance in Norway gives reason for concern.

In general, one of the most important reasons for restructuring of power markets has been to increase the efficiency of the power sector, e.g. [48]. One of the major inefficiencies before deregulation in both Norway and Sweden was considerable overinvestment in generation<sup>14</sup>. So the fact that restructuring and a market based organization reduces the surplus in generation should not surprise anyone. In fact, this can be seen as one measure of success of the restructuring effort. Of course, the down side of this is an occasionally more stressed state of the power system, and in a well-functioning market this leads to higher prices in those situations. But this does not necessarily mean that the system is unacceptably vulnerable.

Still there is obviously reason for authorities to supervise security of electricity supply, given the importance for virtually all aspects of modern society. Although the present study does not reveal severe deficiencies in the present Nordic power market, there is clearly room for improvement in several fields.

Figure 5-1 on the next page illustrates the relations between institutions, actions and the effect of the actions.

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<sup>14</sup> There is no universal agreement on this point, but most experts agree on this subject.



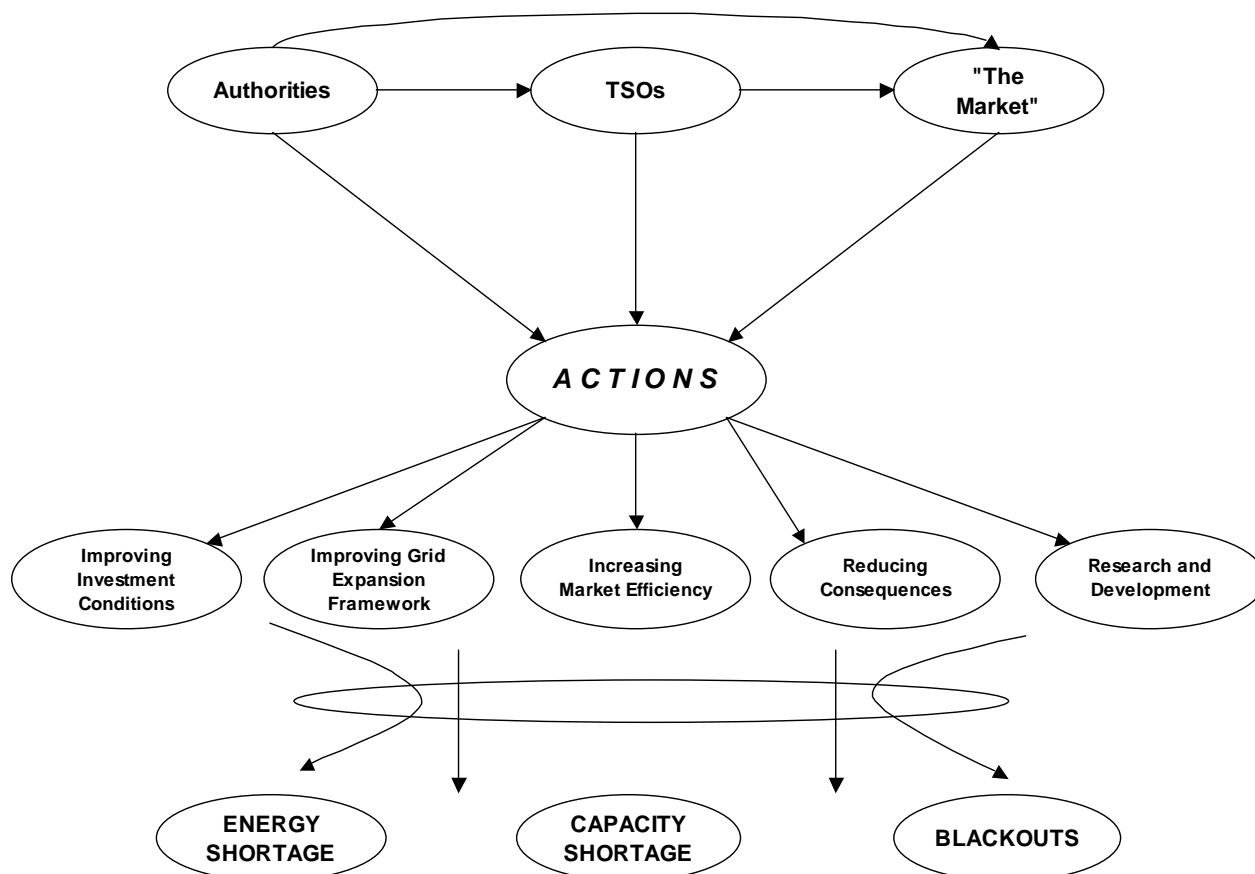


Figure 5-1: Responsibilities, actions and their effects

Actions can be taken by the authorities, including the regulators, the TSOs or the market participants. Actions taken by the authorities can either be direct actions, targeting specific issues, or they can be indirect, influencing the TSOs or the market, e.g. by providing information to the TSOs or market participants. Similarly the actions of the TSOs can be either direct or indirect by motivating market participants.

Potential actions can be divided in four groups:

- Actions that improve the conditions for investment in generation by market participants
- Actions that improve the framework for decisions on expansion of the main grid
- Actions that increase the efficiency of the market
- Actions that reduce consequences of unwanted events

As a final action, we discuss research and development in Section 5.5.

The first two groups are aimed at reducing the frequency of occurrence of unwanted events, they are *preventive* actions. Actions that reduce consequences of unwanted events are *corrective* actions, while increasing market efficiency and research and development include both preventive and corrective actions.

Actions in either of these groups can have an impact on the frequency of occurrence or the consequences of either of the unwanted events, energy shortage, capacity shortage and blackouts.

## 5.1 IMPROVING THE CONDITIONS FOR INVESTMENT IN GENERATION

The analyses in Appendix 1 and Appendix 2 show that the Nordic power system is to some extent vulnerable for prolonged periods of low precipitation and very low temperatures leading to unusually high demand. This vulnerability may either result in periods of very high prices or forced curtailment, or in the case of unusually high demand, increased probability of blackout. Although there are other options, investment in new generation would clearly improve this situation.

### Reduction of regulatory uncertainty

Uncertainty is a major impediment for new investments. In general, uncertainty is inherent to almost every investment decision in all markets, and the uncertainty related to investments in new power generation is a logical consequence of the decision to restructure the power market. However, apart from the uncertainty with relation to future prices, demand and external shocks, which is seen in all markets, there is a considerable additional regulatory uncertainty in the power market, caused by the unpredictability of future political decisions in this highly sensitive area. In this area, there are clearly considerable differences between the Nordic countries. While, on the one hand, it is possible to invest in new nuclear power in Finland, investment in gas-fired plants in Norway is held back because of the uncertainty with respect to potential future limitations and/or taxation of CO<sub>2</sub> emissions. Governments could reduce this uncertainty e.g. by guaranteeing that future political decisions e.g. with respect to taxation would not be given retrospective force before a period of five to ten years.

#### Reduction of regulatory uncertainty

Responsible: authorities

Impact: energy/capacity shortage

### Improving conditions for renewable power generation

Power generation based on renewable energy sources can contribute considerably to increased demand in the future. In the Nordic area Denmark has already a significant contribution from what now is called “new renewable energy sources”, as opposed to traditional large scale hydro, of which the other three countries have considerable shares. Numerous reports exist on this subject, and it is one of the primary actions within the EU [10]. Much is already done within the Nordic countries as well, and we will not discuss it further here. In the medium term, up to some years ahead, renewable power generation cannot contribute significantly to reduce vulnerability, but in the long term this is probably one of the most important actions with respect to the energy balance.

#### Renewable power generation

Responsible: authorities

Impact: energy shortage

### Harmonization of the purchase of Regulation and Reserve Capacity (RRC)

The SKM/COWI report [27] points at the considerable differences and weaknesses in the practices of the Nordic TSOs with respect to the purchase of RRC. According to [27] “The current TSO practice reduces the revenue contribution to cover capital costs for producers, and thus reduce investments in new capacity.” As a *general*

#### Harmonization of the purchase of RRC

Responsible: TSOs

Impact: capacity shortage, blackout

statement, we think this is too strong – revenues from reserve provision can never constitute a major share of total revenues in generation. But *specifically*, with respect to the provision of reserves and incentives to invest in RRC, we strongly support SKM/COWI’s recommendations regarding harmonization of RRC purchases, built on a market-based model that does not subsidize basis capacity. The purchase of RRC is an area that would greatly profit from a common Nordic policy.

## 5.2 IMPROVING THE FRAMEWORK FOR GRID EXPANSION

The transmission grid plays a crucial role in a well-functioning electricity market. If the design of the market and the grid are poorly adapted to each other, transmission constraints may be abundant. Regardless of how these are handled, they increase uncertainty and the possibility of abuse of market power. Moreover, pressure from market participants may tempt the TSOs to stretch the utilization of the network, increasing the probability of blackouts. An optimal grid configuration is hardly without constraints, but many and frequent constraints are an impediment for a well-functioning market. The different handling of constraints within this market probably gives some scope for better utilization of the Nordic grid, but we do not think this has an impact on the *vulnerability* of the system, which is the scope of the present study.

### Improving the framework for grid expansion

Responsible: authorities

Impact: all areas

However, grid expansion generally can reduce vulnerability. Increased interconnections with areas outside Nordel and partly within Nordel can reduce vulnerability for energy and capacity shortage. Strengthening of certain areas of the grid can also reduce the probability of blackouts. It is outside the scope of this study to analyze specifically which areas of the grid should be given priority, but in this context our concern is common Nordic view on priorities. Certainly, a great deal of work in this area is done within the Nordel cooperation. But when it comes to investment, the individual TSOs are constrained by national regulatory frameworks. The description in Section 8.3 shows that there are considerable differences between these frameworks, and the result can be suboptimal national decisions when seen in a Nordic context.

Although there is probably no judicial basis for a common Nordic regulatory framework, harmonization with respect to the regulation of the TSOs would result in closer-to-optimal investments in the Nordic grid. This should be an important task for the Forum of Nordic Energy Regulators. In the longer term this would reduce vulnerability, provided this regulatory framework strikes the right balance between costs and security of supply. Given the crucial role of the transmission grid in the market, one might argue that grid expansion more often should be given “the benefit of the doubt”, given the difficulties in quantifying the benefits of reduced abuse of market power and reduced vulnerability for blackouts.

A final concern with respect to grid expansion is the heavy focus on environmental considerations related to the building of new lines. This must be accepted as a political fact, but it must be

pointed out that in some cases this reduces the possibilities to reduce vulnerability at a reasonable cost.

### 5.3 INCREASING THE EFFICIENCY OF THE MARKET

Although according to our view, the Nordic market is generally functioning well, there are a number of inefficiencies that appear specifically in situations where the power system is under strain. Clearer, more explicit and stronger policies in a number of areas would improve market efficiency and reduce vulnerability.

Although cooperation between the Nordic TSOs is generally good to our knowledge, there are clearly many differences in judicial and regulatory framework, external conditions, culture and in some cases opinions. We do not think these differences are a major source of vulnerability, but in certain situations vulnerability could be somewhat reduced by better coordination. E.g. a higher utilization of interconnections can increase imports during an energy shortage. Unilateral limitations of import or export based on other considerations than pure technical common criteria have an adverse impact on the market and in certain situations on vulnerability.

#### **Harmonization of the Balancing Market**

Even if it is not possible or desirable in the near future to establish one common Nordic TSO or ISO, the Balancing Market, including congestion management is obviously an area for better harmonization. The Nordic cooperation on

balancing control has been improved, and is now closely integrated by the use of a common Nordic regulating power list. The web-based Nordic Operation Information System (NOIS) has contributed to this, and the new tool seems to be appreciated by the operators. The Nordic operators are also discussing further improvements of the NOIS system. However, when it comes to dealing with temporary congestions (bottlenecks) that require rescheduling and deviates from the regulating power list, there is room for closer cooperation and common regulations on a Nordic level. One example is when a bottleneck is identified in one country and the optimal handling of this bottleneck is re-dispatch in a neighbouring country. In such cases, the present regulations are not clear on who should do the regulation necessary and who should pay for this.

#### **Harmonization of the Balancing Market**

Responsible: TSOs

Impact: capacity shortage, blackouts

#### **Improving demand elasticity**

Our analysis clearly shows that increased price elasticity of demand in the short run can reduce vulnerability for shortage of generation capacity and in the long run for energy shortage. This confirms once again numerous other results, and also

one of the conclusions of the SKM/COWI study for the Nordic Council of Ministers. The question is of course *how* to reach this goal. Realization is probably a national concern, but stronger commitment and cooperation at a Nordic level could facilitate the process.

#### **Improving demand elasticity**

Responsible: "The Market" (authorities)

Impact: capacity shortage, energy shortage

In principle, it is the responsibility of market participants to increase demand flexibility in response to relevant price signals. E.g. consumers can invest in multiple heating systems, and retailers can offer rate structures that motivate consumers to be more flexible in the short term. However, there are obviously a numerous barriers that hamper this development, and the authorities have a responsibility to remove these barriers with the objective to enable a well-functioning market in the long run. An example of how authorities can contribute to increased demand flexibility is the Norwegian Government's initiatives to increase the use of heating systems based on hot water distribution (cf. [16] Chapter 5.2.2).

### **Price setting during curtailment**

The discussion in Chapter 4 has shown that there are considerable differences and obscurities between the Nordic countries with respect to price setting in the case of curtailment or a threat of curtailment. This creates additional market uncertainty in such cases. Harmonization and clear rules on a Nordic level would improve this situation.

This is the primary responsibility of the authorities, e.g. through the Forum of Nordic Energy Regulators. However, it appears that e.g. Svenska Kraftnät has the authority to decide price setting in the Balancing Market under special conditions, so the TSOs are also involved.

#### **Price setting during curtailment**

Responsible: authorities (TSOs)

Impact: capacity shortage, energy shortage

## **5.4 REDUCING CONSEQUENCES**

Risk is the result of the probability of an event and its consequences. One way to reduce the consequences of e.g. a blackout is better preparedness of society for such incidents. This has been given considerable attention in e.g. [4], [18], [19], [20], [22], [24], and will not be discussed further in this report.

### **Concession procedures for mobile gas turbines**

During and after the high prices in 2002/03, use of mobile gas turbines by, among others, the TSO was discussed and later analyzed in Norway.

Clearly, any addition of generation capacity in a situation of very high prices and, possibly, threatening curtailment, reduces prices and the probability of curtailment. However, it is doubtful if the TSO should be involved in the provision of generation capacity. On the other hand, authorities could provide for fast procedures for temporary commissioning of such generation in cases of increased vulnerability of the power market. Criteria for such exceptions from normal procedures should be established.

#### **Concession procedures for mobile gas turbines**

Responsible: authorities

Impact: energy shortage

### Contract forms

It has been discussed in Chapter 2.4 that although fixed contracts do not significantly reduce the economic consumer impact over time, they do spread the impact over a longer period, and therefore make high prices more acceptable. On

the other hand, if a large share of consumers has contracts with fixed prices, this reduces demand elasticity, which should be increased. Both concerns can be taken into account by a contract form where consumers buy a fixed amount on a long term contract. Consumption exceeding this amount is paid at the spot price, while consumption below the contract amount is sold back at the spot price. This was shortly indicated in Chapter 2.4. Development of this kind of contracts can both reduce the vulnerability of consumers for very high prices and at the same time increase demand elasticity. In principle, retailers should be interested to reduce their own risk, but present market conditions clearly do not give sufficient incentives. Initiatives at a national and Nordic level to develop and promote contract forms better adapted to a modern power market are therefore a way to reduce vulnerability.

To find contract forms that suit market participants' needs is naturally the responsibility of the market participants. However, the authorities should contribute to the development and implementation of contract forms that improve market efficiency.

#### Contract forms

Responsible: "The Market" (authorities)

Impact: energy shortage

### Reducing the impact of high prices on consumers

As discussed in Chapter 2.4.1, the major problem with high prices is their distributional effect.

Arrangements to compensate vulnerable groups in the case of a prolonged period of very high prices would probably increase the acceptability

of high prices, and therefore improve the efficiency of the market. It is important that such arrangements are implemented in a way that does not reduce demand flexibility.

#### Reducing the impact of high prices

Responsible: authorities

Impact: energy shortage

### System monitoring and protection

Improved state of the art tools for system monitoring and protection increase the possibilities to discover and recognize problematic situations at an earlier stage, thus reducing the probability that such situations develop in a blackout. Even if a

blackout situation develops, the geographical extent can be limited. With respect to the areas with medium risk for blackouts identified in Appendix 3, use of such tools can both reduce the probability and the consequences, moving the respective points down and to the left in the direction of the low risk area in the risk graph.

#### System monitoring and protection

Responsible: TSOs

Impact: blackouts

## Operator training

In the case of cascading blackouts, a major challenge is the lacking experience of operators in handling such situations because of their very low frequency of occurrence. Training on realistic simulators could provide such experience, comparable with pilots' training in flight simulators. Establishment of a common Nordic training simulator and regular training sessions for system operators could be a cost-effective way to implement this action. A development in this direction is already under way through Svenska Kraftnät's Aristo simulator.

### Operator training

Responsible: TSOs

Impact: blackouts

## Maintaining local knowledge and competence

Local knowledge and competence are crucial for maintaining power system security, among other areas in the case of restoring a blackout. This was positively demonstrated in the recent blackout in Western Norway, and negatively in the 2003 blackout in Italy, where retired personnel had to be engaged due to lack of competence. Central coordination combined with delegation to local levels where possible is a good basis to maintain system security in the long run.

### Maintaining local knowledge and competence

Responsible: TSOs

Impact: blackouts

## 5.5 RESEARCH AND DEVELOPMENT

Research and development in power transmission system planning and operation require specialized competence, models and equipment. The industry activity in this area has declined during the last decade due to reduced investments and globalization of the power industry. This has again affected the activity level in universities and research institutions. Indeed, decreasing competence within power systems and power technology is indicated as a source of increased vulnerability in [23]. Considerable synergies can be obtained by coordinating the R&D effort undertaken by the Nordic TSOs in terms of:

- Education and recruitment of staff with the necessary competence to understand and analyze the operation of more and more complex power systems.
- Maintaining the necessary size and competence of research groups with high level expertise.
- Increase the innovation and competitiveness of the Nordic power industry.

### Research and development

Responsible: Authorities, TSOs

Impact: blackouts

## 5.6 SUMMING UP OF ACTIONS

Finally in this Section we sum up the proposed actions in the following tables. The tables show the actions, if they can be implemented at a Nordic (as opposed to national) level and their assumed impact on vulnerability.

Table 5-1: Actions where the authorities have primary responsibility

Actions	Nordic level	impact		
		energy	capacity	blackout
Reduce investment uncertainty		high	high	-
Renewables		medium <sup>15</sup>		
Improving the framework for grid expansion	X	medium	medium	high
Concession procedures for mobile gas turbines		medium	-	-
Reducing the impact of high prices on consumers		high	-	-

Table 5-2: Actions where other institutions have primary responsibility, but where the authorities should contribute to facilitate and speed up implementation

Responsible	Actions	Nordic level	impact		
			energy	capacity	blackout
The Market	Improving demand elasticity	X	high	high	-
The Market	Contract forms	X	medium	-	-
TSOs	Price setting during curtailment	X	medium	medium	-
TSOs	Research and development	X	- <sup>16</sup>	-	high

Table 5-3: Actions where the TSOs have primary responsibility

Actions	Nordic level	impact		
		energy	capacity	blackout
Harmonization of the purchase of RRC	X	-	medium	medium
Harmonization of the Balancing Market	X	-	medium	medium
System monitoring and protection	X	-	-	high
Operator training	X	-	-	high
Maintaining local knowledge and competence		-	-	medium

The impact indication naturally is relative. High impact does not indicate that if only this action is implemented, the system will become invulnerable. It should only be seen as our appraisal of the relative effect of the actions.

With respect to each area of concern, the actions deemed to have high impact can be grouped in the following way:

<sup>15</sup> High in the long term

<sup>16</sup> Research and development naturally are also important with respect to energy and capacity shortage. However, in these areas significant research activity is already going on (e.g. within the development of renewable power generation or market design). In this report we have chosen to focus on the importance of research in the area of power system security in the traditional sense, but supported by new tools and methods.



Table 5-4: Preferred actions to reduce vulnerability with respect to energy shortage

Responsible	Actions	Nordic level
Authorities	Reduce investment uncertainty	
Authorities	Reducing the impact of high prices on consumers	
Authorities/The Market	Improving demand elasticity	X

Table 5-5: Preferred actions to reduce vulnerability with respect to capacity shortage

Responsible	Actions	Nordic level
Authorities	Reduce investment uncertainty	
Authorities/The Market	Improving demand elasticity	X

Table 5-6: Preferred actions to reduce vulnerability with respect to blackouts

Responsible	Actions	Nordic level
Authorities	Improving the framework for grid expansion	X
Authorities/TSOs	Research and development	X
TSOs	System monitoring and protection	X
TSOs	Operator training	X

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## APPENDIX 1 ENERGY SHORTAGE

### A1.1 Approach

In a purely thermal, centrally planned system, the dimensioning criterion for generation capacity is expected peak demand, because the duration<sup>17</sup> of peak demand (typically 5-6000 hours) is considerably shorter than the duration of installed capacity (typically 6500-8000 hours), *and* because the availability of fuel for thermal plants normally is considered unlimited. On the other hand, in a purely hydro system, the corresponding dimensioning criterion is often expected annual consumption of electrical energy, assuming enough reservoir capacity to adapt inflow variations to demand patterns. The main reason for this difference is that the availability of “fuel” (=water) to hydro plants is *not* unlimited, but subject to unpredictable variations in precipitation.

The Nordic system is a mixed hydro-thermal system, with an installed hydro capacity slightly in excess of 50 %, and with considerable import capacities to neighbouring systems. It can be expected that the dimensioning criterion in a centrally planned Nordic system would be a mix of expected peak demand and annual energy consumption. Correspondingly, in a market-based system, it can be expected that either generation capacity or energy supply occasionally can be short, causing high prices. Potential shortage of capacity is analysed in the next Chapter, while the present Chapter assesses situations of energy shortage, primarily occurring in periods of low precipitation like for example the winter of 2002/03.

The EMPS model (shortly introduced in Section A1.2) is used to simulate the energy balance in the Nordic countries for present system (2005), and possible future scenarios for the year 2010.

The main uncertainty with respect to energy availability in the Nordic power system is the variation in hydro inflow to the reservoirs. In the simulations, historical inflow statistics for the years 1931-2000 are used to represent the variation in inflow. This means that when we refer to e.g. the year 1970, this indicates the inflow scenario of 1970 occurring in the present Nordic system, and *not* the Nordic system in 1970 (which would be quite irrelevant for the present analysis). The inflow statistics are not corrected for the possible effects of climate change, which might increase average hydro production, although especially the effects on extreme outcomes (very dry, very wet) are uncertain.

In Norway, the inflow varies between 86 TWh (1969) and 163 TWh (1990), with an average just above 120 TWh. Sweden and Finland have similar variations in inflow, but the absolute variation in TWh is lower since hydropower share is lower. Total inflow to the Nordic system varies between 144 TWh (1969) and 264 TWh (2000).

As discussed in Section 2.4.1, the criterion for classification of energy shortage is loss to Nordic consumers, compared with situations with normal prices. This loss is calculated by comparing

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<sup>17</sup> In this context the duration is defined as annual energy divided by peak demand.

weekly spot prices for each inflow scenario with average price for the week (for the period 1931-2000), and the difference is multiplied by firm load in the respective area in the model:

$$Loss_{Inflow-scenario} = \sum_{\substack{\text{Nordic} \\ \text{areas}}} \sum_{week=1}^{52} (\text{price}(\text{week}, \text{area}, \text{inflow scenario}) - \text{average price}(\text{week})) \cdot \text{load}(\text{week}, \text{area})$$

This gives the above average cost of electricity for a year, assuming all consumers pay the simulated spot price. As argued in Section 2.4.1, longer-term (e.g. annual) contracts can spread the impact to individual consumers over time and to some extent limit this impact, but this calculated number gives a reasonable indicator of the impact of high prices on consumers.

## A1.2 Model description

The EMPS model is used to model the Nordic power market with its connections to the European electricity system. Figure A1-1 shows the model that is used with its division into subsystems (areas). The interconnections between the areas are also shown.

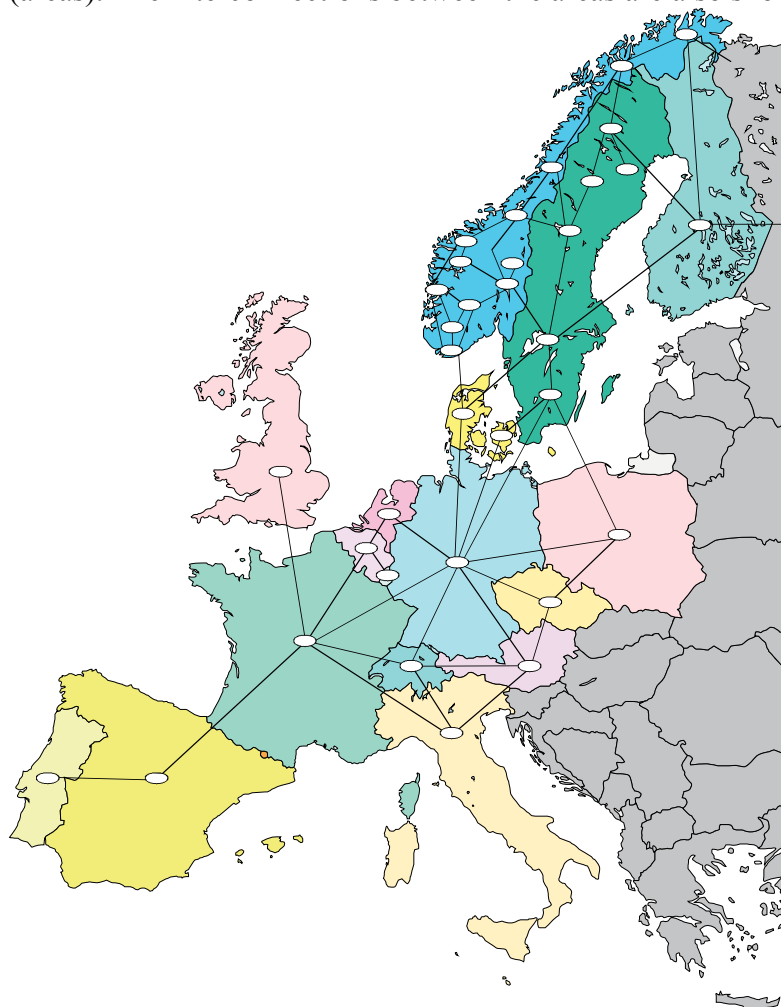


Figure A1-1: The model of the European electricity system. Areas and interchanges in the model

Within each subsystem hydropower, thermal power and consumption (firm power or spot power demand) are represented. In addition the transmission system between subsystems is modelled with defined capacities and linear losses.

The basic time resolution in the model is 1 week, while the week is subdivided in typical demand period like “peak”, “off-peak”, “night” and “weekend”.

The EMPS-model consists of two parts.

- A strategy evaluation part computes regional decision tables in the form of expected incremental water costs for each of a defined number of aggregate regional subsystems. These calculations are based on use of a stochastic dynamic programming-related algorithm for each subsystem, with an overlaying hierarchical logic applied to treat the multi reservoir aspects of the problem.
- A simulation part evaluates optimal operational decision for a sequence of hydrological years. Weekly hydro and thermal-based generation is in principle determined via a market clearance process based on the incremental water value tables calculated for each aggregate regional subsystem. Each region’s aggregate hydro production for each time step is distributed among available plants using a rule-based reservoir drawdown model containing a detailed description of each region’s hydro system.

Results from simulations with the EMPS model include, among others, prices, generation, demand, exchange etc. All results are given for individual simulated inflow scenarios, as average values or as percentiles.

An important issue in the present context is the handling of demand in periods of shortage of supply. The basic mechanism for handling shortage of supply is involuntary curtailment of demand, which is modelled as a “supply of last resort” at a very high cost. In the present study a cost of 365 €/MWh is used, which also constitutes a price cap in the model. In the EMPS model curtailment is used only when no more energy is available (due to lack of water), whereas in the real world the authorities must use curtailment in advance when the chance of running out of water is very high.

In the EMPS model, elasticity of demand is modelled in various ways, but there is no difference between long-term and short-term elasticity in demand. With the data used in the present study, it is probable that long-term elasticity underestimated. With very high prices over a long period of time, it is probable that the reduction in load would reduce the amount of curtailment and possibly eliminate the need for forced curtailment (depending on how high the authorities are willing to let the price go). The elasticity in demand for extreme prices is unknown, and therefore hard to model. Thus, when the model results show certain amounts of curtailment, reality might well be that real curtailment would be lower, or even that it could be avoided. Still, prices would obviously have to be very high to realize the necessary demand reduction, which qualifies such situa-



tions for the classifications discussed in Section 2.4.1, regardless if physical curtailment would be necessary or not.

A further description of the EMPS model is given in Appendix 5Appendix 2.

### A1.3 Analysis of present system (2005)

A description of the system and assumptions on load levels and new capacity is given in Appendix 4.

#### A1.3.1 Main simulation results

Figure A1-2 shows the average weekly prices in the simulation of 2005 for each of the countries. A price is calculated for each area in the model. For Norway and Sweden the area in the model that represents the main load area is shown.

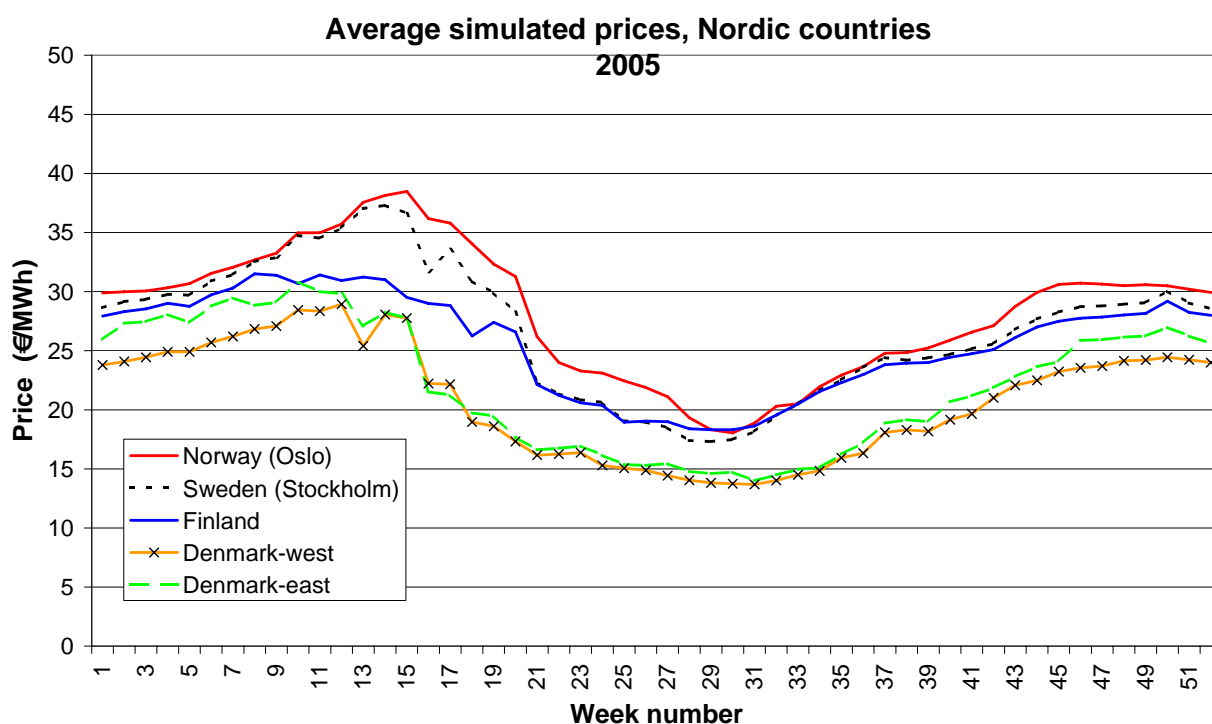


Figure A1-2: Average weekly prices 2005 (average of the 70 simulated inflow scenarios)

Prices are highest in Norway since Norway on average imports electricity from Denmark and Sweden. Denmark has the lowest prices since it exports electricity. Prices also show seasonal variation, they are high in the winter and low in the summer. The EMPS model does not use the concept of “system price”, but it can be assumed that this is best represented by the area with the highest load, the Central-Sweden / Stockholm area. Average simulated price for this area is 26.9 €/MWh.

Three of the simulated scenarios result in curtailment, as shown in Table A1-1:

Table A1-1: Inflow years causing curtailment for 2005 scenario (TWh)

	Norway	Sweden	Finland	Sum
1942	4.5	1.0	1.9	7.4
1970	3.5	0.2	0.7	4.4
1941	0.7	0.1	0.4	1.1

The table shows that Norway has most of the curtailment, which is natural since it is almost a 100% hydro-based system. The model uses curtailment in 3 of the 70 inflow scenarios, which gives a probability of curtailment of 4%. The division of curtailment between Sweden and Finland should not be taken too literally because the hydro model used for Finland is less detailed than for Sweden and Norway. The correct interpretation of Table A1-1 is that two scenarios result in significant curtailment in Norway and some curtailment in Sweden and Finland, while the third scenario has some curtailment in Norway, and possibly a minor quantity in Sweden and Finland. In such situations, the way demand responds to prices and authorities' (non-) intervention are decisive factors for if physical curtailment actually will incur or not. Another important issue is cooperation between the Nordic authorities.

In Figure A1-3 the simulated prices for Central Sweden (including Stockholm) is shown for each of the inflow scenarios. For the three inflow scenarios that cause curtailment, we see that the prices become extremely high at the end of the winter. As discussed before, at such price levels it is hard to predict what the prices will be, other than that they will be "very high".

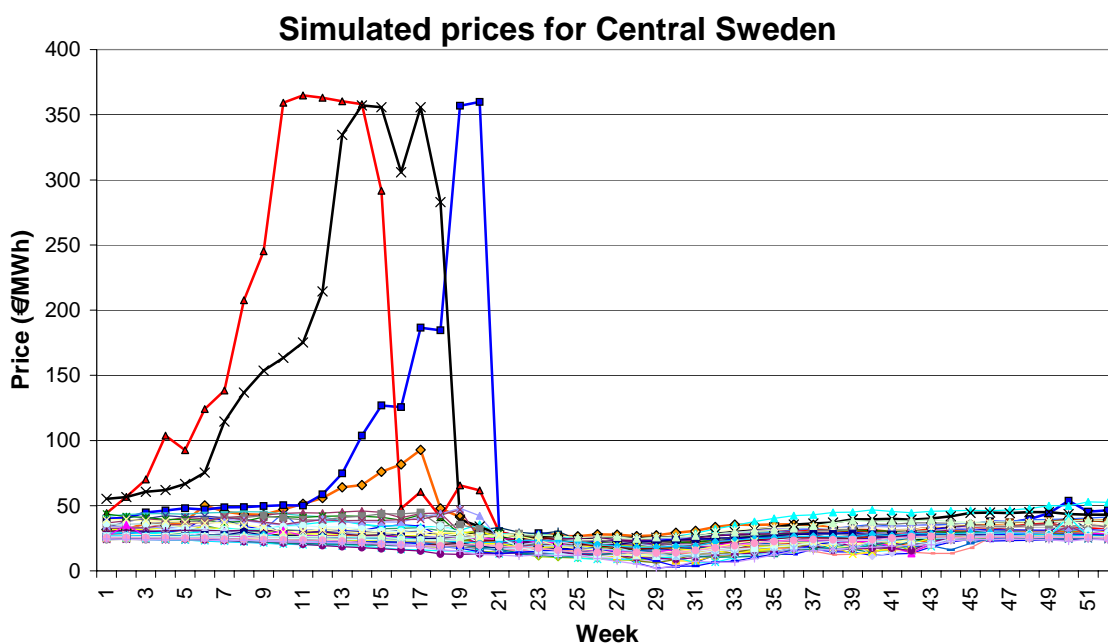


Figure A1-3: Simulated prices for Stockholm for all inflow scenarios

The next figure shows the consumer loss caused by high prices, as defined in Section A1.1.

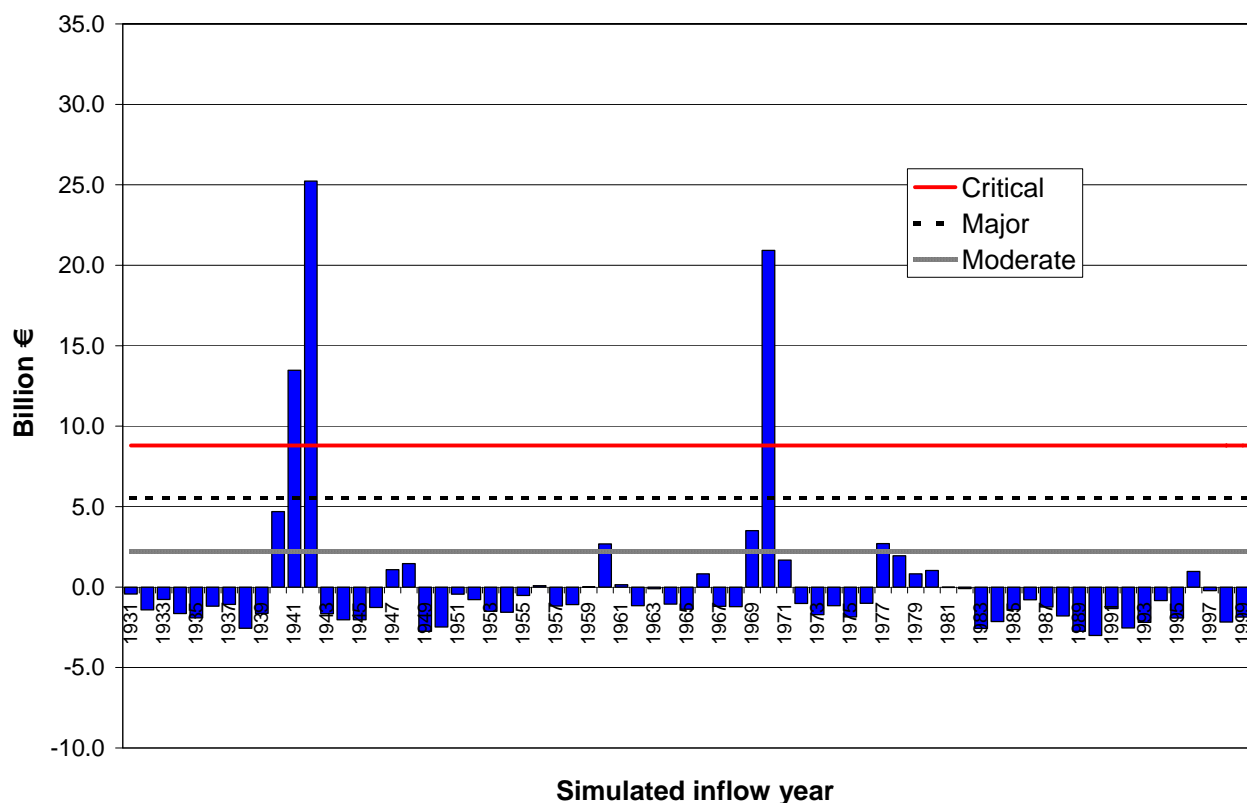


Figure A1-4: Consumer loss caused by high prices (cf. Section A1.1), present system (2005)

The figure shows that seven of the simulated scenarios have an impact defined as moderate or worse. Three have an impact that is defined as major or worse, and all three are also critical.

### A1.3.2 Other incidents reducing energy supply

Apart from reduced inflow, it is conceivable that also other events can reduce supply and cause energy shortage. To illustrate the effect of such events, two incidents has been simulated here:

- 1) 500 MW outage on the cable between Denmark and Norway for 5 months. One pole of the cable between Norway and Denmark is out from week 35 in the first year to week 17 in the second year, a total of 35 weeks.
- 2) Outage of largest nuclear unit for 3 months. Oskarshamn 3 (1160 MW) is out from week 45 in the first year to week 4 in the second year, a total of 12 weeks.

The following two tables show the estimated curtailment volumes for each of these scenarios.

Table A1-0-2: Curtailment, cable failure (TWh)

	Norway	Sweden	Finland	Sum
1942	5.7	1.2	2.0	8.9
1970	4.6	0.3	0.9	5.8
1941	1.5	0.1	0.0	1.6

Table A1-0-3: Curtailment, nuclear failure (TWh)

	Norway	Sweden	Finland	Sum
1942	5.1	1.3	2.0	8.4
1970	4.5	0.3	0.9	5.7
1941	1.6	0.1	0.5	2.2

Comparison with Table A1-1 shows that the effect of these simulated events is relatively minor, compared with the effect on energy supply from inflow deficits. This is further illustrated in Figure A1-5, showing the additional cost to consumers caused by these events.

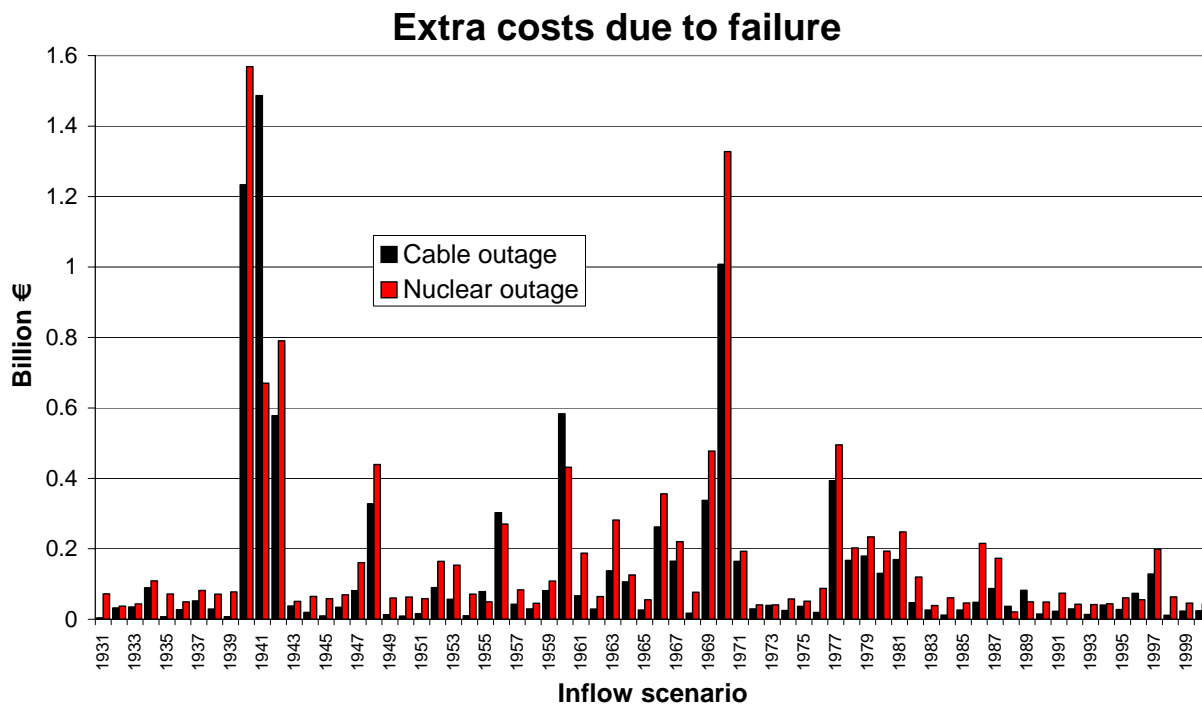


Figure A1-5: Extra cost to consumers due to failures

Figure A1-5 shows that the impacts of the failures are minor compared to the impact of low inflow years. But it also shows that if the failure occurs in a low inflow year, the consequences are higher. For both failures, the impact of one of the inflow scenarios (1940) goes from “Moderate” to “Major” due to the failure. For the other 69 inflow scenarios the classification is unchanged.

Of course, worse events than those considered here can occur. A realistic event is a failure in a nuclear plant that is deemed to affect all nuclear plants of the same type, and makes it necessary to shut down all these plants for a prolonged period of time. Something similar happened in Japan in 2003. Although possible, the probability of such an event is extremely low, and in any case very hard to assess. It is the logical result of the choice of using nuclear energy, faced by all countries with significant shares of nuclear energy. The special result in the strongly integrated Nordic market is that it would affect other countries as well – but this is not different from the fact that low inflow to Norwegian hydro plants affects the other Nordic countries as well.

#### **A1.4 Analysis of future system (2010)**

A description of the system and assumptions on load levels and new capacity is given in Appendix 4.

Three different scenarios have been simulated for 2010:

- Scenario 2010-0: Assumptions on the power system in 2010 as described in Appendix 4.
- Scenario 2010-1: As 2010-0, but no Norwegian gas power plant (-800 MW gas power)
- Scenario 2010-2: As 2010-0, but Barsebäck 2 is not decommissioned (+600 MW nuclear power)

Scenario 2010-0 represents the best guess of the system in 2010, whereas 2010-1 and 2010-2 represent scenarios with respectively weakened and improved Nordic energy balance. This is chosen so that we can study the influence of the energy balance on the prices.

##### **A1.4.1 Main simulation results**

The following tables (Table A1-4 to Table A1-6) show the amount of curtailment in the 2010 scenarios. As could be expected, they show that as the Nordic energy balance is weakened, the amount of curtailment increases (2010-2 has the best, 2010-1 has the worst Nordic energy balance).

Table A1-4: Inflow years with curtailment for 2010-0 scenario (TWh)

	Norway	Sweden	Finland	Sum
1942	6.0	2.0	1.2	9.2
1970	4.0	0.9	0.1	5.0
1941	0.9	0.2	0.6	1.8

Table A1-5: Inflow years with curtailment for 2010-1 scenario without Norwegian gas power plant (TWh)

	Norway	Sweden	Finland	Sum
1942	7.9	2.5	1.3	11.7
1970	8.0	1.3	0.2	9.5
1941	4.5	0.5	0.6	5.6
1940	0.01		0.01	0.02

Table A1-6: Inflow years with curtailment for 2010-2 scenario with Barsebäck 2 running (TWh)

	Norway	Sweden	Finland	Sum
1942	5.3	1.4	1.5	8.3
1970	3.3	0.4	0.1	3.8
1941	0.3	0.0	0.6	0.9

Scenario 2010-1 has curtailment in 4 of 70 inflow years, which gives a probability of curtailment of 6%. The other two scenarios have curtailment in 3 of 70 inflow years, which gives a probability of curtailment of 4%.

The following figures show simulated average prices for each of these scenarios:

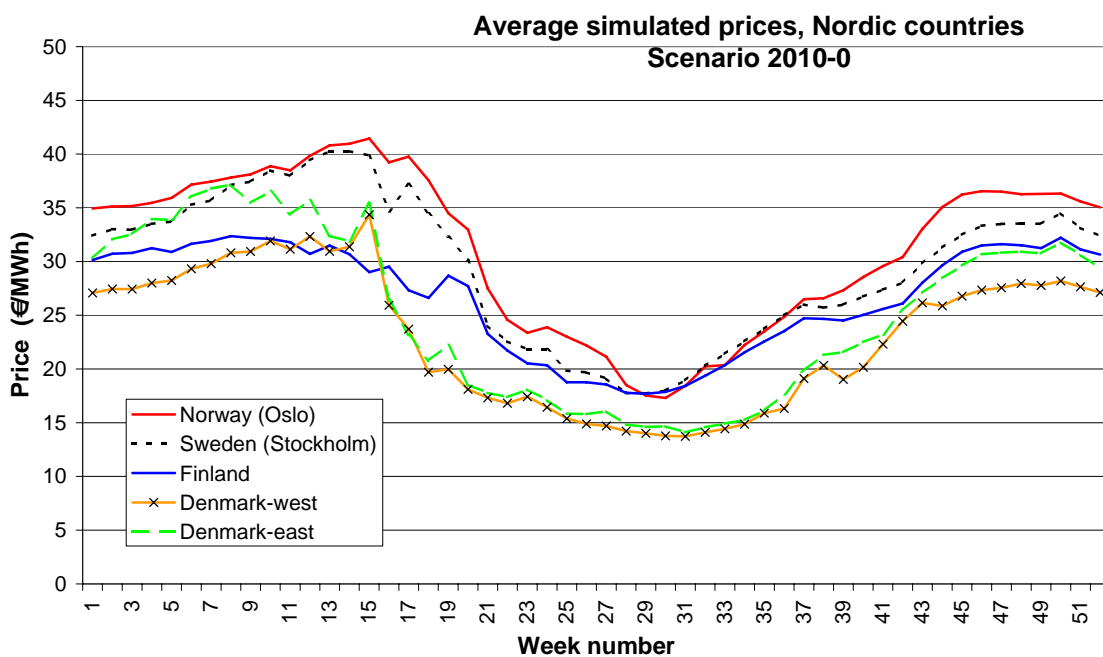


Figure A1-6: Prices for Scenario 2010-0: Basis scenario

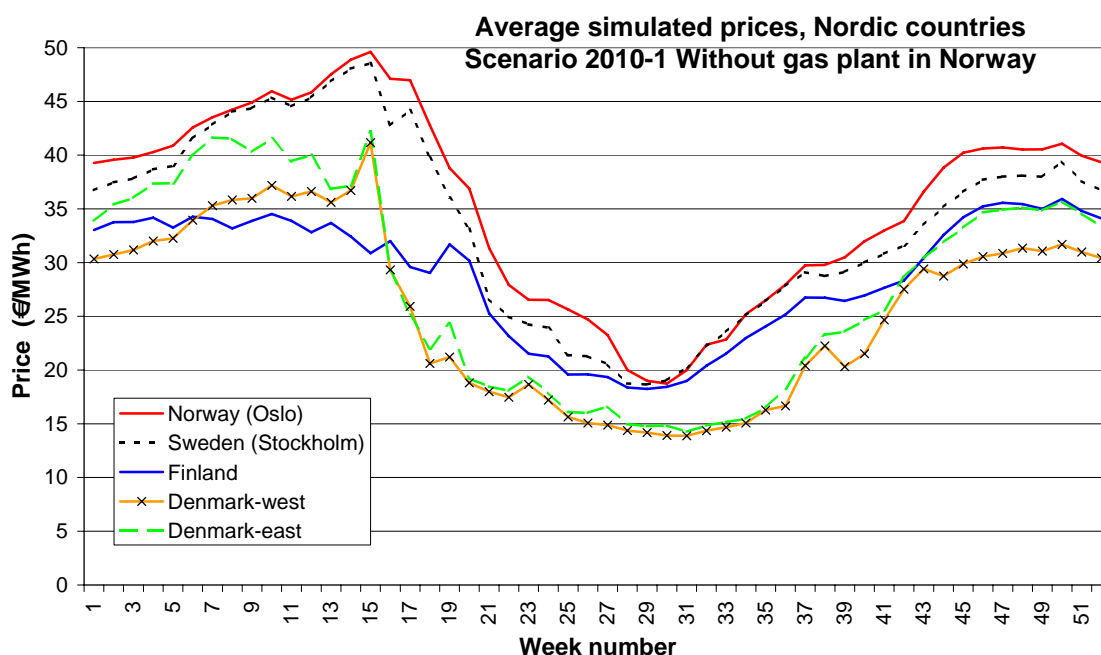


Figure A1-7: Prices for Scenario 2010-1: Without Norwegian gas plant

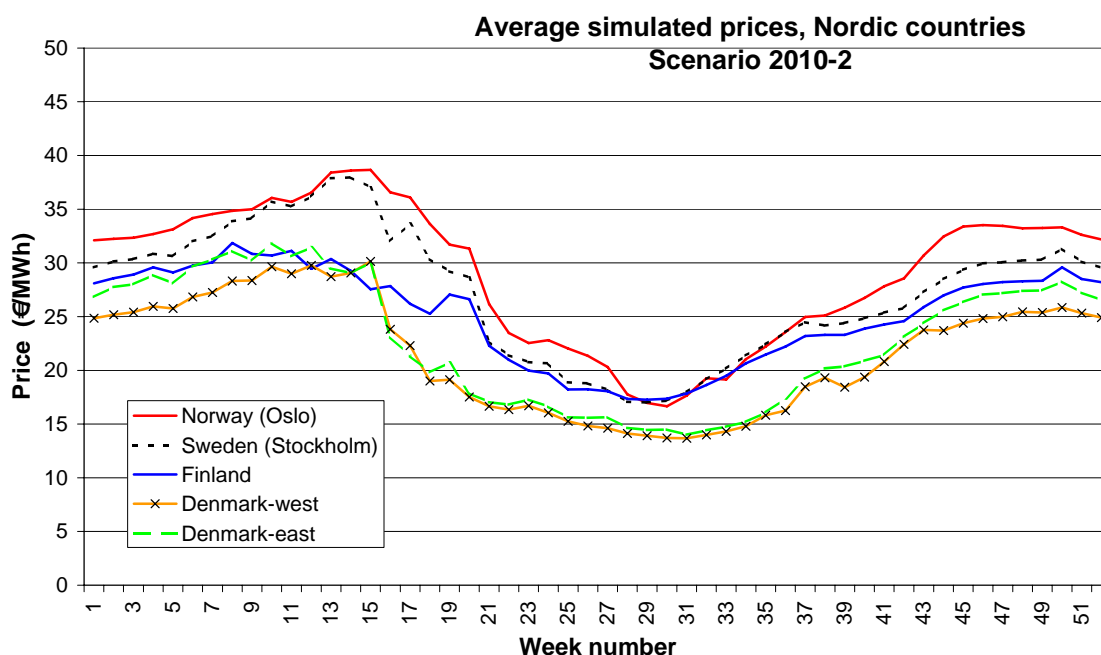


Figure A1-8: Prices for Scenario 2010-2: Without decommissioning of Barsebäck 2

The average prices for Scenarios 2010-0, 2010-1 and 2010-2 are 29.6, 33.7, 27.3 €/MWh respectively. Especially with respect to the second scenario, it is appropriate to remind of the average spot price in 2003, which was 36.7 €/MWh: the *expected* average spot price in 2010 is only 10 % lower than the actual price in 2003 in the case where no gas plants are built in Norway, and where this is not compensated with other comparable increase in supply or reduction in demand.

It can be seen from these figures that when the Nordic energy balance is weakened, both average prices and seasonal variation in the price increases. This means that the average cost to the consumers increases. The next figures show that also the variation in the electricity bill increases. With a poorer Nordic energy balance, the prices in dry years go even higher.

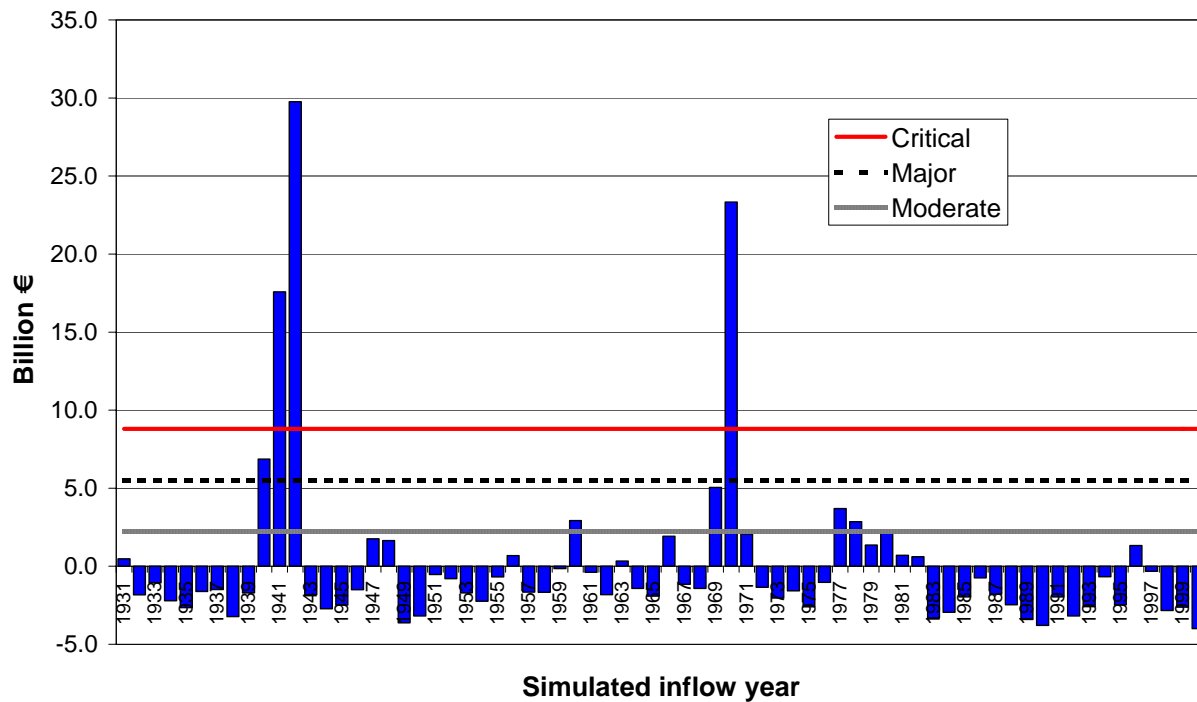


Figure A1-9: Consumer loss caused by high prices, Scenario 2010-0

A similar situation can also occur in the case of delay of the commissioning of the 1600 MW Oikiluoto 3 nuclear power plant in Finland.



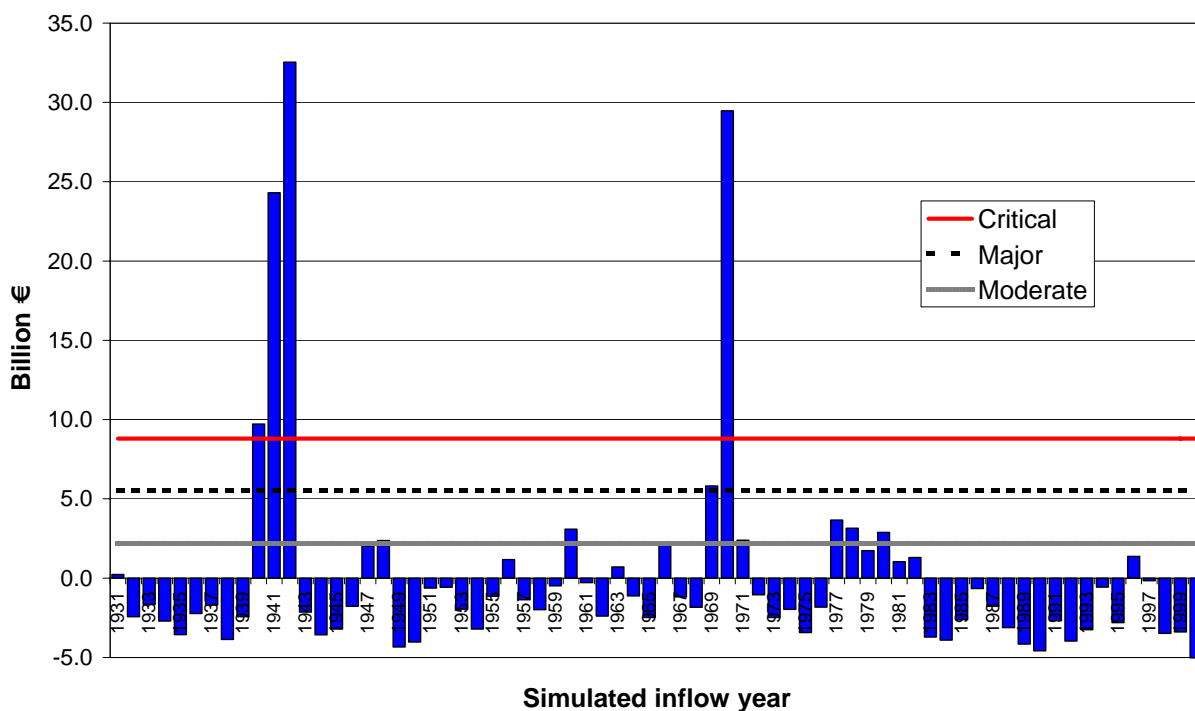


Figure A1-10: Consumer loss caused by high prices, Scenario 2010-1

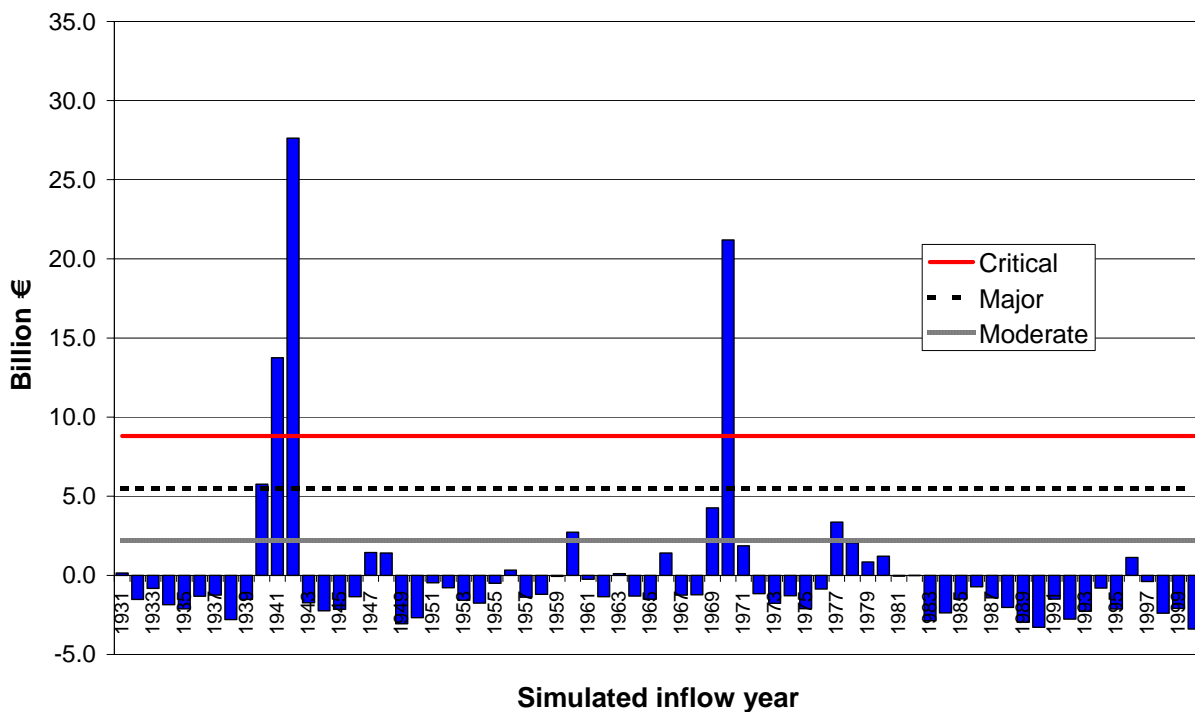


Figure A1-11: Consumer loss caused by high prices, Scenario 2010-2

Table A1-7: Number of years with classified consequences

consequence scenario:	2005	2010-0	2010-1	2010-2
moderate or worse	7	8	12	7
major or worse	3	4	5	4
critical	3	3	4	3

Although not dramatically, comparison with the results for 2005 does show that the probability of unwanted events in the form of high prices increases somewhat for the most likely scenario 2010-0. For scenario 2010-1 without Norwegian gas plants, the probability of “moderate or worse” events is 12/70 or 17 %. Roughly speaking, price increases as seen in 2002/03 *or considerably worse* would be seen every six years.

Improved Nordic energy balance, reduces the variation in the price, while weakened Nordic energy balance increases the variation in price. Scenario 2010-1 gives the highest increase in cost to consumers in low inflow years. This is the scenario with the poorest Nordic energy balance.

### A1.5 Summary of results from energy simulations

Figure A1-12 shows the yearly average price for Central Sweden for each inflow scenario, and for each of the situation scenarios (2005, 2010-0, 2010-1, 2010-2). The area “Central Sweden” is chosen because it is closest to the system price.

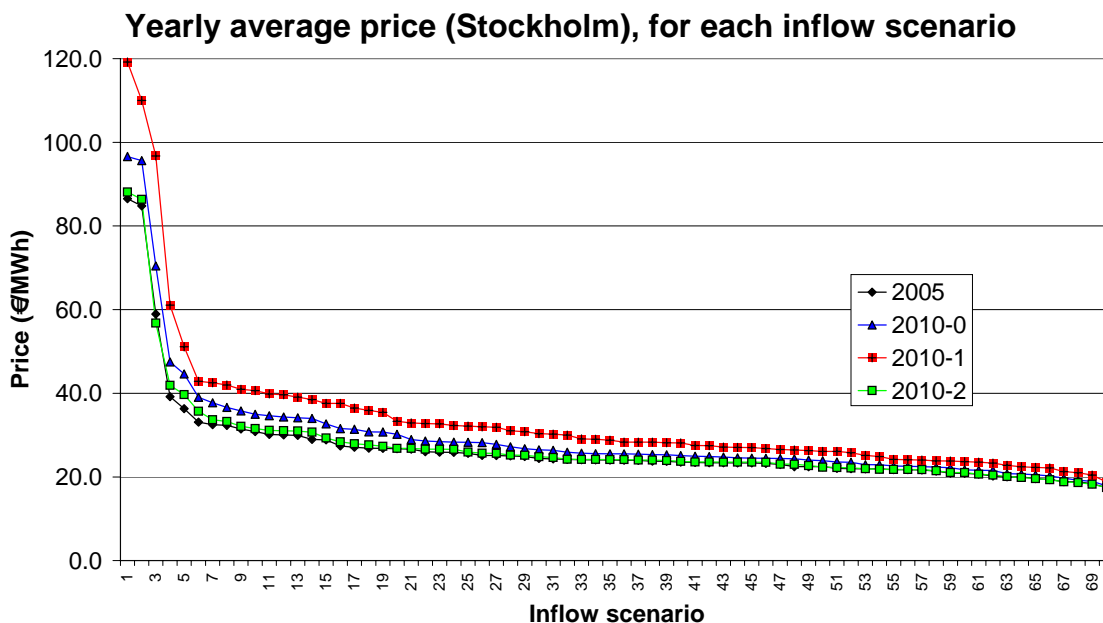


Figure A1-12: Yearly average prices for Stockholm for each inflow scenario

In 2003 the average system price for the year was 36.7 €/MWh. The highest monthly prices in the winter 2002-2003 was in December 2002 with 74.4 €/MWh and in January 2003 with 71.7 €/MWh. For the present stage (2005), 4 out of 70 inflow scenarios give a price higher than the year 2003. Assuming that the inflow statistics give a good representation of the variation in inflow this gives a 6% chance of prices higher than the actual 2003 prices.

Probabilities of higher than 2003 prices:

- 2005: 4 out of 70 scenarios, which gives a probability of 6%
- 2010-2: 5 out of 70 scenarios, which gives a probability of 7%
- 2010-0: 7 out of 70 scenarios, which gives a probability of 10%
- 2010-1: 14 out of 70 scenarios, which gives a probability of 20%

The following tables summarizes average annual prices:

Table A1-8: Average simulated prices for Central Sweden

Scenario	Average price (Stockholm)
2005	26.9 €/MWh
2010-2	27.3 €/MWh
2010-0	29.6 €/MWh
2010-1	33.7 €/MWh

When the Nordic energy balance is weakened (i.e. needs to import more electrical energy), the average prices increase. In addition the consequence of extremely low inflows increases; extremely high prices get even higher. This can be seen from Figure A1-9, Figure A1-10 and Figure A1-11. Scenario 2010-1 (Figure A1-10) has the worst energy balance, and the consequence of low inflow is highest for this scenario.

Prices will occasionally reach the price level of 2003, and they can even become significantly higher if the worst inflow scenarios occur. If the Nordic energy balance keeps getting worse, the probabilities of extreme prices will increase.

Table A1-9: Occurrence per year for high price incidents

	<b>2005</b>	<b>2010-2</b>	<b>2010-0</b>	<b>2010-1</b>
Critical	0.04	0.04	0.04	0.06
Major	0.04	0.06	0.06	0.07
Moderate	0.10	0.10	0.11	0.17

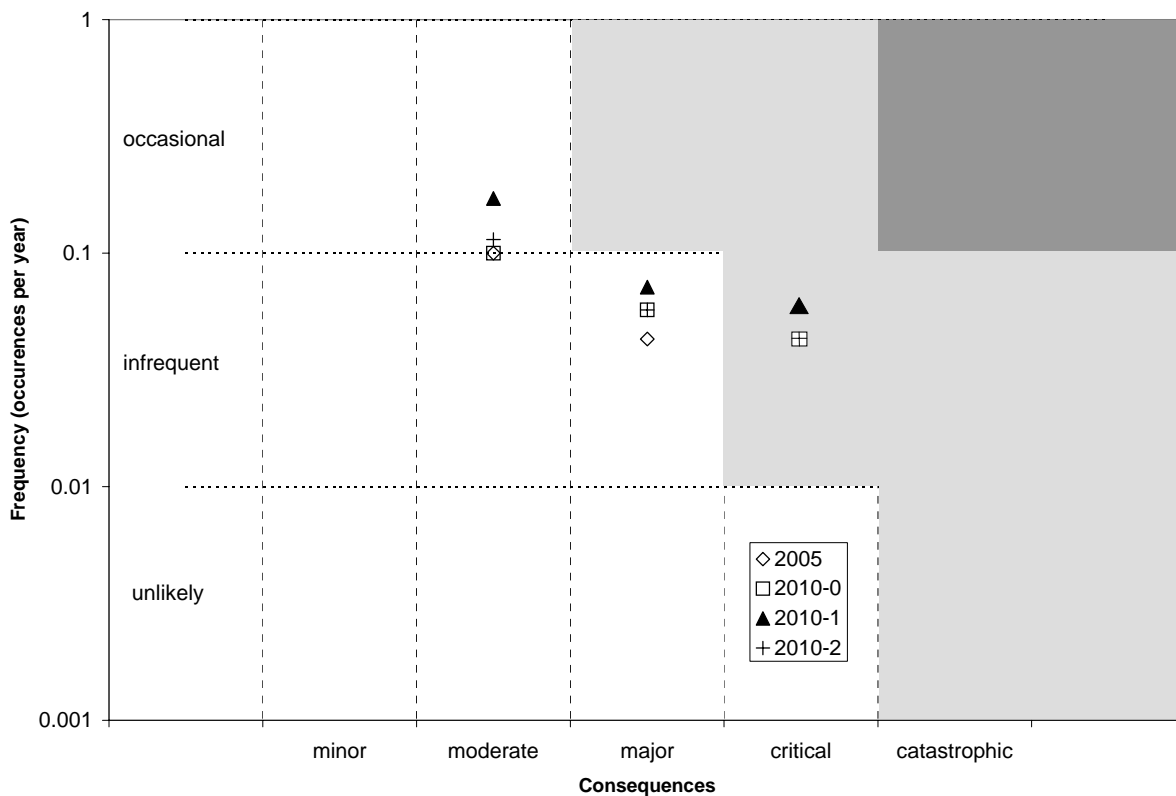


Figure A1-13: Risk graph energy shortage

In Figure A1-13 the results are shown in the risk graph introduced in Section 2.5. The plot shows that the system is in a medium risk state both presently and in 2010 with respect to energy shortage according to the classifications and criteria in Chapter 2. The plot also shows the increased probabilities of unwanted consequences, which look smaller than they are because of the logarithmic scale. Table A1-7 better illustrates that the probability of critical incidents increases when the energy balance is weakened. The plot does not show the somewhat increased severity within each class of consequences: a loss to Nordic consumers of 33 billion Euros cannot be distinguished from a loss of 25 billion Euros – both are assumed critical. Minor and catastrophic incidents are not defined for the energy shortage simulations.

There is a certain possibility that the EU Water Framework Directive 2000/60/EC will reduce hydro generation in the Nordic countries, but if this will be the case and what the size of the reduction would be is impossible to know presently. Implementation of the Directive is planned between 2010 and 2012.

## **A1.6 Uncertainty**

There is always uncertainty involved in model calculations, which raises questions about how realistic the results are. Important factors in the EMPS calculations presented here are:

### **Demand elasticity**

This has already been mentioned. Because prices in excess of 120 €/MWh over a sustained period of time have never occurred in the Nordic market, it is very hard to know how consumers will react in such cases. If real elasticity is higher than assumed, prices will be lower than calculated for the most critical outcomes. We do not think this would reduce prices below the level defined as “Critical”, but these outcomes might become less critical in terms of consumer impact.

### **Model philosophy**

The model takes a single-owner view of the power system, and uses available generation and transmission options based on total system optimization. In reality, there are many market participants that together determine how the available resources are used. It is conceivable that a single-owner system optimization gives a better utilization of the resources, and consequently lower prices, i.e. the model results are too optimistic. The consequence of this may be that the model underestimates the number of unwanted high-price events.

### **Import**

The capacities of interconnections between the Nordic countries and with countries outside the Nordic area are lower than their physical limits in the model. This takes into account that interconnections often will not be utilized fully according to the principles used in the EMPS model. For a number of reasons real utilization may be lower than an ideal model would assume. Therefore it can be argued that the model imports more energy at an earlier stage than would be the result of the individual market participants’ decisions. This would result in a stronger energy balance and lower prices in the model than in reality. This effect is probably strongest in inflow scenarios with moderate consequences. In the scenarios with critical consequences prices are so high that it is conceivable that imports also would be correspondingly high. This is an example of the previous point, and may result in an underestimation of the number of high-price events.

### **How representative are inflow statistics**

In the model calculations historical inflow statistics for the period 1931-2000 are used. Average inflow is clearly higher from 1980 to 2000 than it was in earlier periods. It has been suggested that this may be related to ongoing climate change, and that for this reason inflow statistics from the 1930’s and 1940’s no longer are representative for present conditions. The present state of knowledge is insufficient to draw clear conclusions on this issue, but it should be taken into account that the possible effects of climate change beside increased average precipitation in important hydro-power areas also include more extreme weather conditions. Consequently, the extremely dry autumn of 2002 is not in contradiction with assumptions on climate change. Our conclusion is that this is a very uncertain issue, and that it is preferable to simulate a broad spectre of outcomes to represent the variability of hydro inflows. This suggests that it is better to use a long period of historical inflows than a short period.

## **APPENDIX 2 GENERATION CAPACITY SHORTAGE**

In the context of the present study, capacity shortage is defined as a situation where available generation capacity and imports together are insufficient to serve demand without violating the constraints of the grid, while keeping satisfactory reserve levels.

A capacity shortage may show either in the spot market or in real time or both. A capacity shortage in the spot market can manifest itself by the fact that the supply and demand curves do not intersect, and there is neither a defined market price nor a clearing volume. The present strategy of NordPool is to reduce demand bids proportionally until the demand and supply curves meet. The price is set to the technical maximum price, presently the lowest value of EUR 2000, NOK 16500, SEK 18000 and DKK 15000. NordPool emphasizes that this is a technical limit only that can be changed on short notice, even only one day.

A capacity shortage situation may alternatively occur in real time, either because demand becomes higher than expected or because of outages of generation or transmission in an already stressed situation. If the list of available objects in the Regulating Power Market is exhausted, there is a situation where severe frequency deviations and grid overload may occur.

The distinction between these two forms of capacity shortage is not necessarily as clear as indicated here. A central issue here is how reserves are handled. In a completely “free” market, without any TSO initiatives to ensure reserves, all available generation capacity would be bid into the spot market in a situation where there is a danger of supply and demand curves failing to intersect, because prices would be very high. In this case the spot market may clear, but insufficient reserves would remain to operate the system reliably in real time. The Nordic TSOs naturally have foreseen this situation, and taken various measures, cf. [27]. The TSO measures can work in two ways:

- attract capacity from the generation or demand side that was not otherwise available, and thus increase available capacity
- reserve existing capacity for the Balancing Market, and therefore prevent it from being used in the spot market

SKM/COWI argue in [27] that capacity that is being paid for by the TSO should in principle never be used in the spot market. In this case, the TSO would subsidize base capacity, and therefore reduce the incentives to invest in new capacity on market conditions. However, under some doubt, they make an exception for the case where supply and demand curves fail to intersect in the spot market, provided the price is set sufficiently high. The argument is that this capacity would be used anyway in the Balancing Market, cf. Sections 4.3.1 and 4.3.2 in [27].

This shows the ambiguity between a capacity shortage in the spot market and in the Balancing Market. If a capacity shortage occurs in the spot market, it can be avoided by using capacity reserved for the Balancing Market, but this will transfer the problem to the Balancing Market – and make it the responsibility of the TSOS, while security of supply is reduced. If a capacity shortage

will show in the spot market, and ultimately if it will result in involuntary<sup>18</sup> controlled curtailment of load, depends partly on how low the TSOs are willing to let reserve levels drop before taking action.

Of course there *can* in principle occur situations where the spot market clears without problems, but in real time the list of objects in the Balancing Market is exhausted and a capacity shortage occurs. However, the whole purpose of the TSO's policies to provide reserve capacity is to avoid that situation, and the probability is deemed small as long as reserve requirements and recommendations are satisfied.

In the following, we will first describe the approach used to assess the Nordic power system's vulnerability with respect to capacity shortage. Afterwards, an analysis of the present (2005) and future (2010) Nordic will be presented. The main focus of the analysis will be peak demand during cold weather.

## **A2.1 Vulnerability for capacity shortage – approach**

### **A2.1.1 Power supply and demand**

The basis for the analysis of capacity shortage is the expected development of supply and demand in the Nordic countries. The primary data source is Nordel, but a number of other sources is also used, among them TSOs, industry federations etc. A complete discussion is given in Appendix 4. The following table shows the resulting capacities for 2005:

Table A2-1: Assumed installed capacity (MW) as of 31 December 2004

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Total</b>
Installed capacity, total	13 082	16 866	28 041	32 608	<b>90 597</b>
Available capacity, total	8 558	14 852	24 565	28 879	<b>76 854</b>
Reserve requirements	1 225	1 340	1 743	1 713	<b>6 021</b>
Available less reserve requirements	7 333	13 512	22 852	27 166	<b>70 863</b>

When estimating *available* capacity, it is assumed that Nordel reserve requirements and recommendations are fully provided by the generation system, cf. Appendix 4.

With respect to peak demand, three scenarios are considered:

- A *normal* winter with an assumed occurrence of every other year
- A *cold* winter with an assumed occurrence of once in ten years
- An *extreme* winter with an assumed occurrence of once in thirty years

<sup>18</sup> "Involuntary" curtailment means physical, non price-based shedding of load. As long as prices make consumers reduce demand, it is defined as voluntary, even if consumers obviously are not very satisfied with this situation.

Table A2-2: Assumed peak demand (MW) in 2005

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Total</b>
Normal winter	6 650	14 660	22 200	27 000	<b>70 510</b>
Cold winter	6 900	15 000	23 350	29 000	<b>74 250</b>
Extreme winter	6 900	15 000	23 750	30 500	<b>76 150</b>

No elasticity of demand is assumed, but a further discussion of this important issue is included in the analysis in Sections A2.2 and A2.3.

Corresponding numbers for 2010 are given in the next two tables:

Table A2-3: Assumed installed capacity (MW) in 2010

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Total</b>
Installed capacity, total	13 772	18 466	30 462	32 693	<b>95 393</b>
Available capacity, total	8 572	16 452	26 049	28 564	<b>79 637</b>
Reserve requirements	1 225	1 340	1 713	1 743	<b>6 021</b>
Available less reserve requirements	7 347	15 112	24 336	26 821	<b>73 616</b>

Table A2-4: Assumed peak demand (MW) in 2010

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Total</b>
Normal winter	7 155	15 930	23 530	27 900	<b>74 515</b>
Cold winter	7 430	16 300	24 800	30 000	<b>78 530</b>
Extreme winter	7 430	16 300	25 200	31 500	<b>80 430</b>

### A2.1.2 Capacity shortage scenarios

The estimates of available capacity in the previous Section are based on “expected conditions”, i.e. conditions that can be expected on average cold winter day and normal grid conditions. The latter implies limited congestion on specific interfaces, as can be expected during winter peak demand. With respect to *vulnerability*, the important issue is what happens under special conditions, and what kind of special conditions can lead to situations with serious consequences.

With respect to demand, special conditions are represented by observing cold winters and even extreme winters. With respect to supply, special conditions occur when generation availability is reduced or when import availability is less than expected. We therefore consider several scenarios to represent these situations. We also attach an illustrative probability to each scenario. These should not be taken in a literal sense, but as an indication of magnitude. Outages of major lines are not considered here, as they are viewed as part of power system outages covered in the next Chapter.



### **Reduced availability of import**

Physical import capacities to the Nordic countries are given in the Nordel statistics for 2002 [28], and amount to 4150 MW in 2005 and 4750 MW in 2010. However, physical capacities are no basis for realistic import volumes, due to a number of factors like:

- transfer capacity during actual peak conditions
- rules and agreements governing the utilization of an interconnection
- network conditions behind the interconnection
- availability of spare generation capacity in the exporting country

In [29] Nordel estimates a need for 2500 MW import from outside the Nordic area, and states that it is probable that total demand can be satisfied with this level of import. The same report also discusses the fact that the surplus of generation on the European continent must be expected to decrease in the coming years as a result of liberalization.

On this background, we analyze the following scenarios:

1. Ample import availability, 2500 MW import available during peak load. Illustrative probability 80 % in 2005 and 60 % in 2010.
2. Reduced import availability, 1250 MW import available during peak load. Illustrative probability 20 % in 2005 and 40 % in 2010.

A considerable share (approximately 1400 MW) of the import to the Nordic area comes from Russia to Finland. Reasons for reduced import can be reduced or failing import from Russia or limited availability of surplus generation capacity during peak load on the European continent.

### **Reduced hydro availability**

Normal hydro availability is assumed to be 88 % in Norway and Sweden and 86 % in Finland (Nordel). This is primarily due to hydrological conditions, but also takes into account that some capacity will be unavailable behind congested lines or because of failure.

There is a certain possibility that available hydro capacity is lower than expected. One reason can be low reservoir levels like in 2002/03. This is probably not a critical situation with respect to the balance between generation capacity and peak demand, because low reservoir levels increase prices and reduce demand, resulting in lower peak demand.

The following hydro scenarios are defined:

1. Normal hydro conditions, availability 88 % of installed capacity in Norway and Sweden, 86 % in Finland. Illustrative probability 90 %.
2. Reduced hydro conditions, availability 86 % of installed capacity in all countries. Illustrative probability 10 %.

### **Availability of nuclear generation**

One of the special features of nuclear units is their size, varying from 445 to 1160 MW. This means that outage of one unit has a considerable effect on the capacity balance during peak conditions. In its capacity balances, Nordel normally assumes 100 % availability of nuclear generation.

Given the low probability of forced outages, this is not unreasonable on average, though slightly optimistic, as illustrated by the following argument.

We assume that maintenance can be scheduled in such a way that no nuclear unit are out for planned maintenance during peak load conditions<sup>19</sup>. However, units sometimes have forced outages (“snabbstopp”). In most cases, units can be brought back on line in the course of 24 hours (KSU). Based on [30] a typical frequency of one forced outage per nuclear unit per year is assumed, i.e. the probability of one unit being out on a random day is  $1/365=0.00274$ . There are 11 nuclear units in Sweden and 4 in Finland. The probability that at least one of these units is not available can then be estimated as 4 %, with an expected unavailable capacity of 805 MW in 2005. The number of nuclear units is the same in 2010, because Barsebäck 2 is expected to be decommissioned, while a new 1600 MW unit is expected to be commissioned in Finland in 2009. This increases the expected unavailable capacity to 872 MW.

This results in the following scenarios with respect to nuclear availability:

1. All nuclear units available. Probability 96 %.
2. At last one unit not available. Probability 4 %, expected outaged capacity 805 MW in 2005 and 872 MW in 2010.

For simplicity, a nuclear outage is always assumed to take place in Sweden. In the analysis of the results this means that the balance for Sweden is somewhat too pessimistic, and for Finland too optimistic.

### **A2.1.3 Event trees**

Based on three demand scenarios and the supply scenarios from the previous Section, an event tree can be constructed, showing the probability of each combination of events and the resulting capacity balance.

From the root of the tree, there are three branches, representing three different peak demand scenarios:

- Normal winter
- Cold winter
- Extreme winter

Basically, these scenarios are based on recurrence intervals. In the present context each of these scenarios represents outcomes of peak demand within a certain interval of peak demand, and we have to assess the probability that a random winter falls within each interval. The interpretation of a recurrence interval of two years for a normal winter is that that demand will be at this level *or higher* every second year on average. Alternatively, the probability of peak demand at normal

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<sup>19</sup> This is probably slightly optimistic, because maintenance sometimes has taken more time than planned, and units have not become available before late autumn. November and December may occasionally also show very high demand levels.

winter level or higher is 50 %. Correspondingly, the probability of demand at cold winter level or higher is 10 % (recurrence interval 10 years) and at an extreme winter level or higher 3.3 % (recurrence interval 30 years).

In a probability density function, these probabilities represent the area under the function value to the right of the respective percentile values, illustrated by the dashed vertical lines in Figure A2-1. However, in the event tree we need the probability of each individual scenario, not the accumulated probability of a scenario and all other scenarios with higher demand. The sum of the probabilities of all scenarios must be equal to one. The probability of a mild winter is 50 %, and demand levels in such winters are assumed to not to be of interest with respect to capacity shortage (and this assumption will be confirmed by the results for normal winters later). Then the probability of all other scenarios together must also be 50 %.

Somewhat arbitrarily we now assign the probabilities 0.30, 0.15 and 0.05 to the three scenarios. These probabilities are represented by the area of the respective rectangles in Figure A2-1, which can be viewed as a discrete version of the probability density function. The idea behind the probabilities is that the cold and extreme winter scenario each represent an interval of demand outcomes, and not just one outcome. To assign probability of 0.033 ( $=1/30$ ) to the extreme winter scenario would underestimate the fact that there are other outcomes close to the once in thirty years outcome that have a similar high demand. This is illustrated by the discrete version of the probability density function.

Like in the previous Section, probabilities are primarily illustrative, to be able to classify consequences.

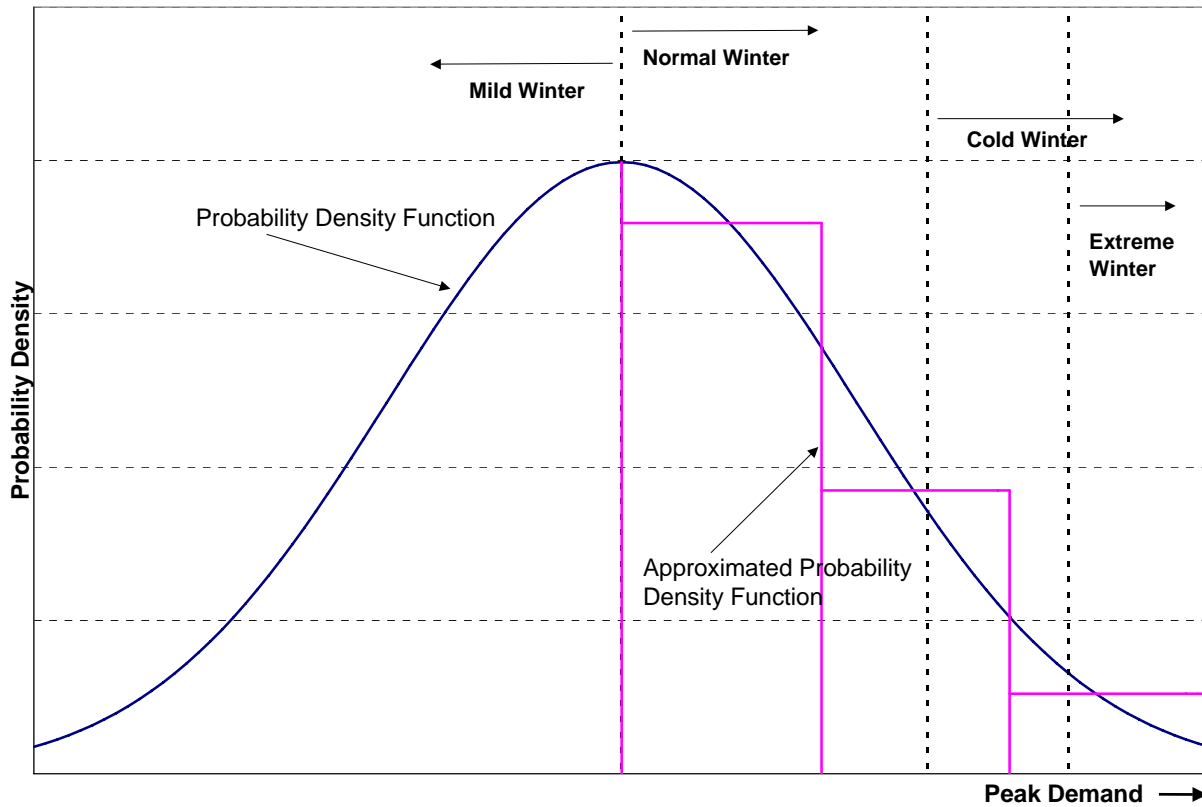


Figure A2-1: Illustration of demand scenario probabilities with a probability density function

The remainder of the event tree models the 2x2x2 different outcomes of the supply scenarios in the previous Section. Each final branch of the tree shows the resulting generation capacity surplus or deficit, and the probability for this event. An example of an event tree is given in the figure on the next page.

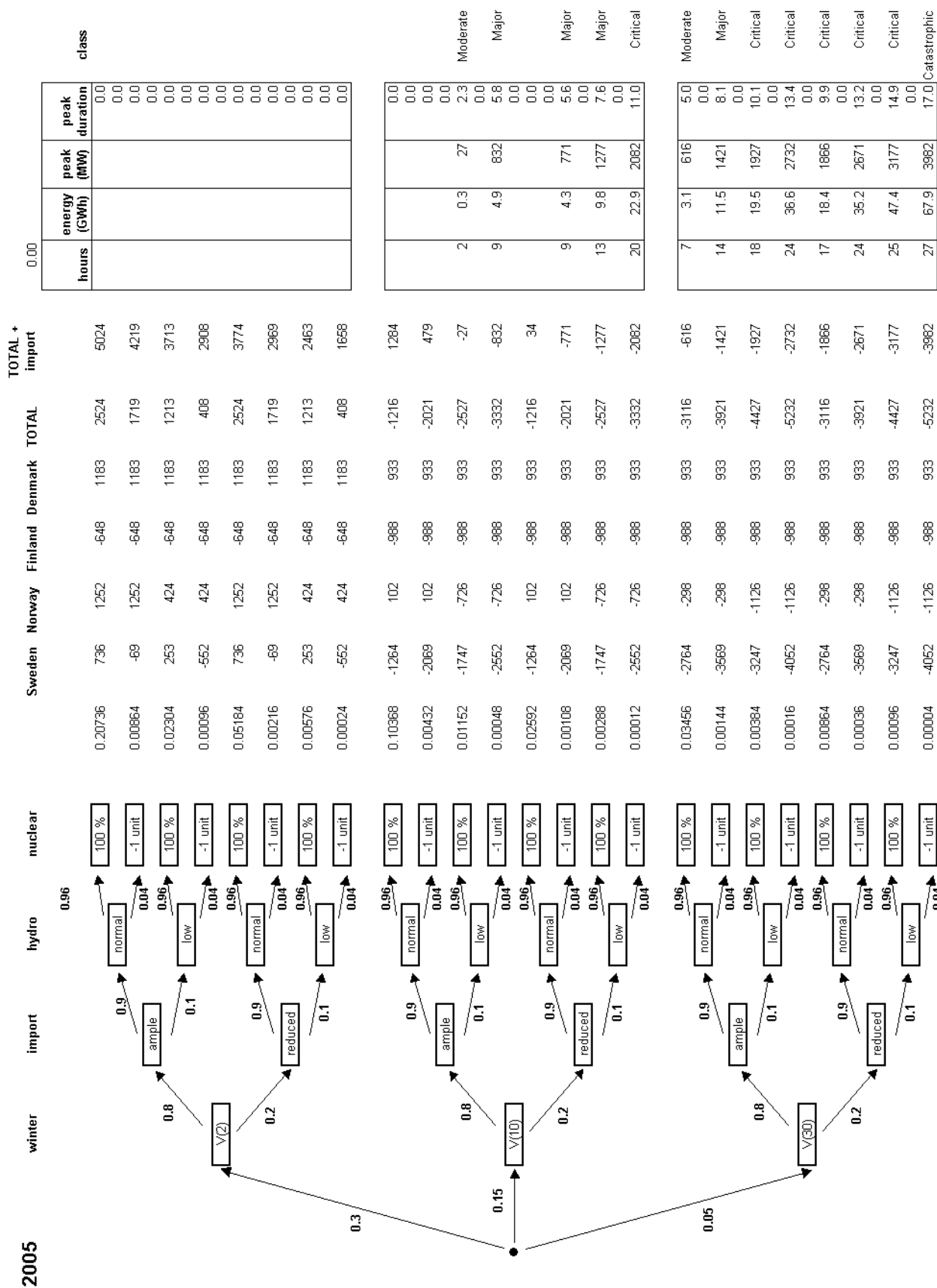


Figure A2-2: Example event tree

Two crucial points, not explicitly modelled in the event tree are:

1. The utilization of reserves
2. Demand elasticity

The basis for the determination of reserves are the Nordel requirements for primary reserves (frequency regulation and disturbance) and recommendations for secondary (fast) reserves, as described in Appendix 4, totalling slightly more than 6000 MW. The question is how much of these reserves should be available under peak demand conditions. If the requirements and recommendations are strictly conformed to, the risk of cascading faults and blackouts is kept low, but the probability of necessary curtailment to be able to satisfy reserve requirements increases. On the other hand, if avoidance of *involuntary* shedding is given a high priority, reserve levels drop and the probability of blackout increases. Unfortunately, there presently there exist no methods or tools to determine the optimal balance between these conflicting considerations. According to Annex 9 in [29], normal requirements to fast reserves can be relaxed in the case of a capacity shortage, however never to a total level lower than 600 MW in the synchronized Nordic power system. This minimum level of reserves must be supplied by generators and be available for the deficient grid area(s), and should be flexible with respect to output variations. If it is impossible to maintain at least 600 MW, load will be shed involuntary in the deficit area(s)<sup>20</sup>. We believe that operating the system with only 600 MW is fast reserves would increase the probability of black-out disquietingly, but we are not able to quantify this within the limitations of the present study.

To analyze the effect of the assumptions on acceptable reserve levels, the following scenarios are presented for each stage:

- Full primary and secondary reserve requirements, no demand elasticity
- 50 % reduction in secondary reserve requirements, no demand elasticity
- 50 % reduction in secondary reserve requirements, demand reduction 1000/300/100/50 MW for Norway/Sweden/Finland/Denmark respectively

Because the focus of the present study is on *vulnerability*, our main concern is involuntary shedding of load or blackout. By reducing reserve requirements in real time, involuntary load shedding can be avoided or reduced in cases of very high demand. However, if resources earmarked for reserves are unavailable in the spot market, a situation where the Elspot market does not clear might occur. In Norway, up to 2000 MW of reserves is unavailable in the spot market, of which 800-1200 MW are generation resources. In Sweden and Finland a considerable share of the reserves exists of thermal generation at the disposal of the TSO. In principle, these are not available in Elspot, but Svenska Kraftnät can make them available under special circumstances. In Denmark the handling of reserves used to be part of agreements between Elkraft-System and Energi E2 in East-Denmark and between Eltra and Elsam in West-Denmark. This "Power Plant Agreement" ("Kraftværksaftalen") expired in 2003. New bilateral agreements ensure the availability of

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<sup>20</sup> Of course, it is assumed that all elastic demand is reduced to the level where it becomes inelastic and that all *voluntary* load shedding has been effected.

reserves in Denmark. Given the surplus capacity in Denmark, a situation with a deficiency in Elspot is anyway hardly probable.

When Elspot does not clear, according to NordPool rules, spot market demand is reduced proportionally to make the market clear, and the price is set to the technical price cap. Even if the situation would end without involuntary shedding of load, this would be a major disruption of the market. The result would be reduced credibility and maybe a decrease in volume and therefore liquidity both in Elspot and the derivative markets, which would hurt market development.

For 2010 we also look at the following situation:

- 50 % reduction in secondary reserve requirements, demand reduction 1000/300/100/50 MW for Norway/Sweden/Finland/Denmark respectively, no gas plant in Norway and no nuclear plant in Finland

The rationale behind the last scenario is that it is well-known that gas plants are controversial in Norway and that the planned nuclear plant in Finland is a very large project. In general, delays of large projects cannot be ruled out. Alternatively, these scenarios present the situation shortly before the commissioning of these projects.

The forecasts of peak demands do not explicitly take into account price elasticity, although the relatively slow growth of peak demand may implicitly be a result of increasing price elasticity. After the high prices and resulting demand response in Norway in 2002/03, there appears to be some agreement about a certain price elasticity, and that this will effectively reduce peak demand if there is a shortage resulting in very high prices. However, the experiences from 2002/03 are irrelevant for what will happen in the case of a few days with very high spot or Balancing Market prices. In the former case spot prices were high for a long time, and consumer prices were adjusted accordingly, at least in Norway. Only very few consumers have hourly metering and contracts based on hourly prices. In the case of a few days with high prices, very few consumers have an economic incentive to reduce demand. It must be admitted that it is highly uncertain what actually would happen in the case of e.g. three days with 10 hours with prices like 2000 Euro/MWh because there is no similar experience with such prices. But it is impossible to rely on demand elasticity, at least until it has been clearly established and verified.

#### **A2.1.4 Energy curtailed for a given capacity shortage**

To assess the damage to the consumers whose demand is involuntary curtailed, we have to estimate the cumulative amount of demand that is curtailed. If there is a certain capacity deficiency in one peak hour, there will probably be a deficiency in several other hours as well, given the relatively flat demand duration curve on a peak demand day. Figure A2-3 shows the observed Nordic demand duration curve for 5 February 2001, together with a linearized version. By scaling the demand duration curve to an estimated peak demand and using the linearized version, an estimate can be made of total curtailed demand, given a certain deficit in the peak hour. Curtailed demand is given by the shaded area in the figure.

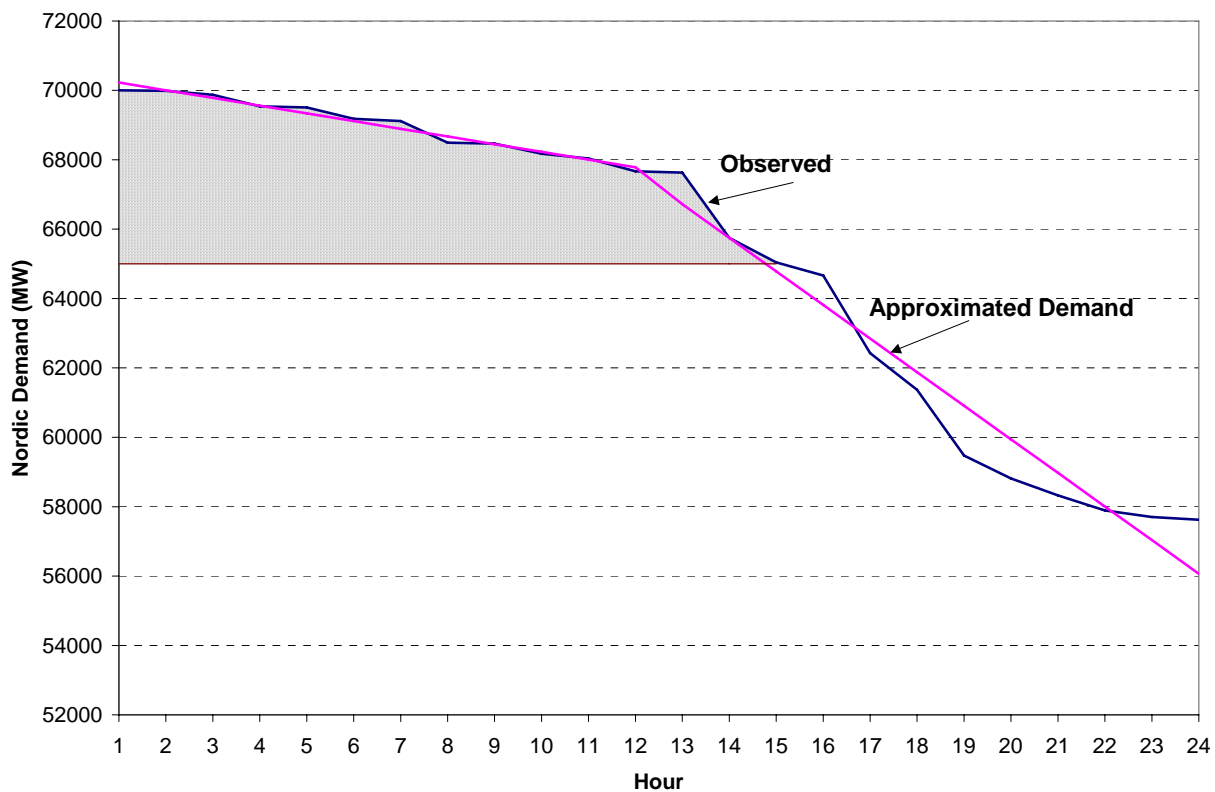


Figure A2-3: Observed and approximated Nordic demand duration curve 5 February 2001 and illustration of curtailed demand in the hypothetical case of 5000 MW shortage of generation capacity.

### A2.1.5 Other situations with potential capacity shortage

#### Late spring inflow start

With their considerable share of hydro generation, Sweden and Norway may occasionally face problems with covering peak demand when the reservoirs are at their lowest levels, shortly before the snow starts melting. Normally, the snow melting period will start and reservoirs start filling up between week 14 and 18 in Sweden and week 16 and 20 in Norway, cf. the figures below.



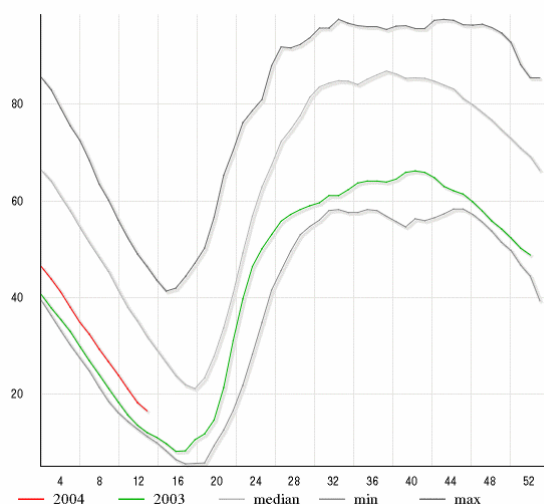


Figure A2-4: Reservoir contents Sweden  
(Source: Nordpool)

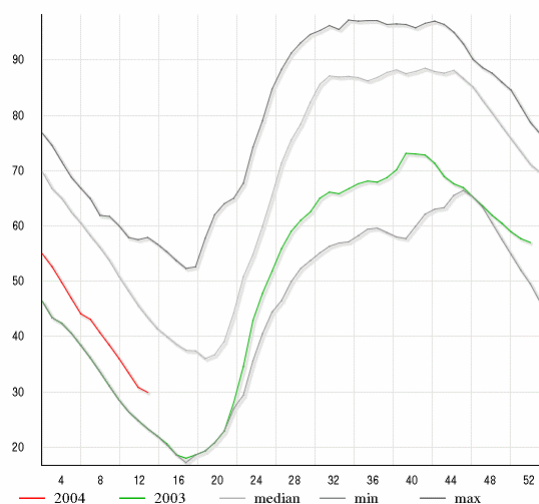


Figure A2-5: Reservoir contents Norway  
(Source: Nordpool)

In the case of a late spring, reservoir levels may become very low, and the available capacity of many plants may become seriously reduced. On the other hand, demand is also much lower in this period than during the winter period, but if the weather is cold, demand may still be considerable, especially in Norway. Figure A2-6 shows duration curves of demand from mid April to mid May for Sweden and Norway. The curves show the percentage of time in this period that demand is over a certain level on an expected value basis.

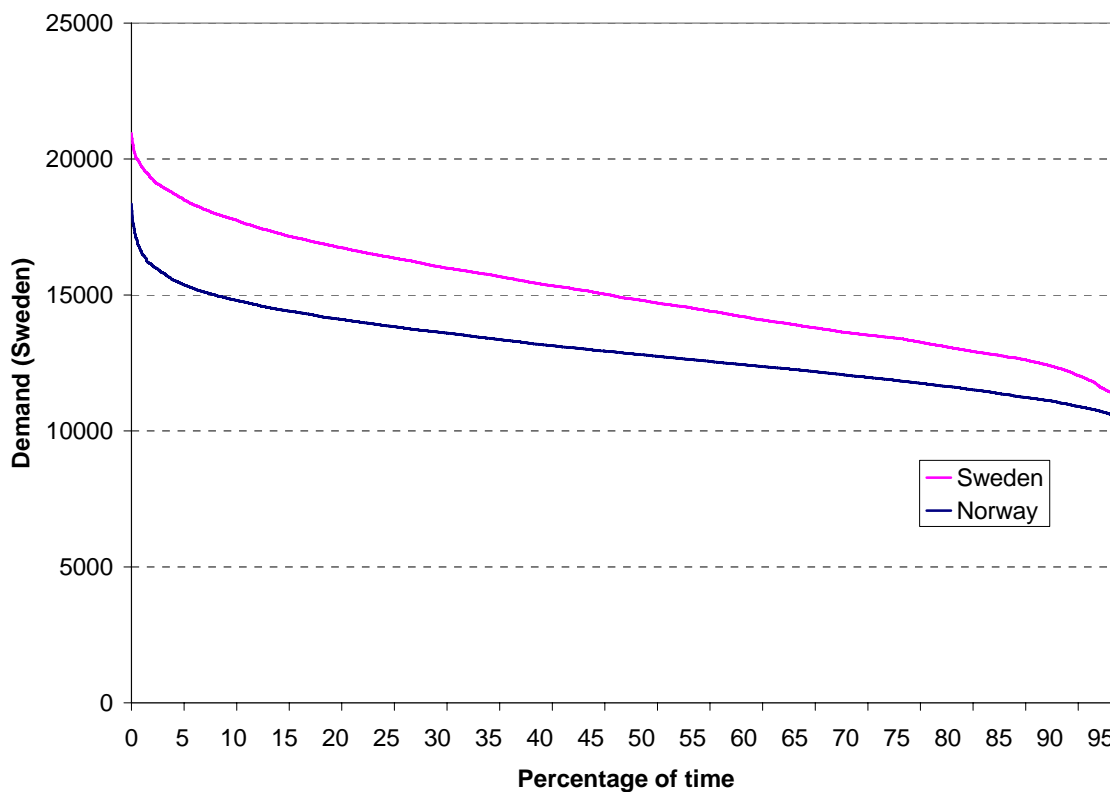


Figure A2-6: Duration curve of demand from mid April to mid May (1996-2002)

The highest load during this period was 80 % and 77 % of the highest winter load for Sweden and Norway respectively. An additional problem is that a late spring start coincides with low, though not necessarily extremely low temperatures.

To quantify the probability of sufficient generation being available to cover this demand, a thorough analysis of the availability of the hydro system in this period is necessary. This was not possible within the constraints of the present project. However, for both the present and future stage we will estimate how much hydro generation has to be available to cover this demand, and discuss if it is reasonable to assume this.

### Local problems

There are two areas in the South- and North-Western part of Norway respectively that have limited generation resources and relatively weak connections with the other parts of the Nordic system. As a result, problems that may occur on a national or even Nordic basis like a shortage of generation capacity have a higher probability of occurring within these areas. The increased vulnerability of these areas to blackouts is discussed in the next Chapter. Here we only state that the probability of a generation capacity shortage is greater in these areas than in the other parts of the system, especially shortly before the snow starts melting.

### Periods of rapid load increase

Generally, the system is more vulnerable during periods of rapid load increase. An outage in Tokyo in 1987 was actually caused by this phenomenon. An important reason for the increased vulnerability is the way frequency regulation works, which results in periodically reduced frequency and therefore reduced primary reserves when demand increases rapidly. A power system fault at an adverse moment during rapid load increase can more easily develop in blackouts than the same fault during other periods. An example of such frequency variation is shown in Figure A2-7.

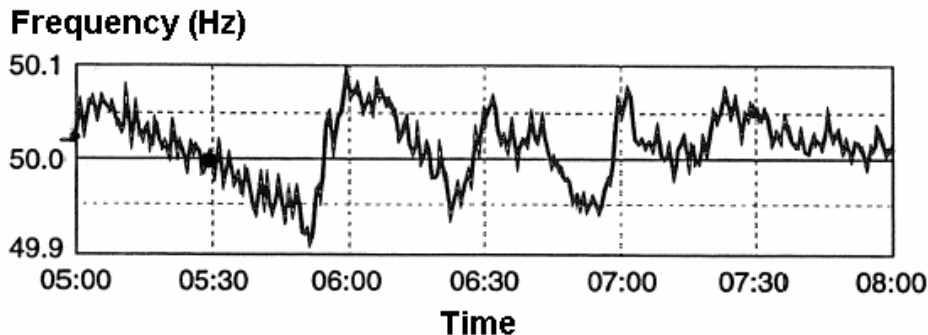


Figure A2-7: Observed frequency in the Nordic grid on 8 February 1999 (Source: [31])

It is pointed out in [31] that this day was special due to greater than normal deviations between the demand forecast and actual demand, but the principal pattern is representative. With the given pattern, a major fault at 05:45 would be much more difficult to handle than the same fault at a time when load and therefore frequency is more stable.

Naturally, the TSOs are aware of this problem and have taken counter measures. Nevertheless, the period of rapid load increase early in the morning presents specific challenges and a period of increased vulnerability. We will however not try to quantify this in the present study.

## A2.2 Vulnerability for capacity shortage, present system, 2005

Figure A2-8 shows the risk graph for capacity shortage in 2005. The horizontal axis depicts consequence classes, while the vertical axis shows probabilities. The light shaded area represents medium risk and the dark shaded area high risk, as discussed in Chapter 2.5.

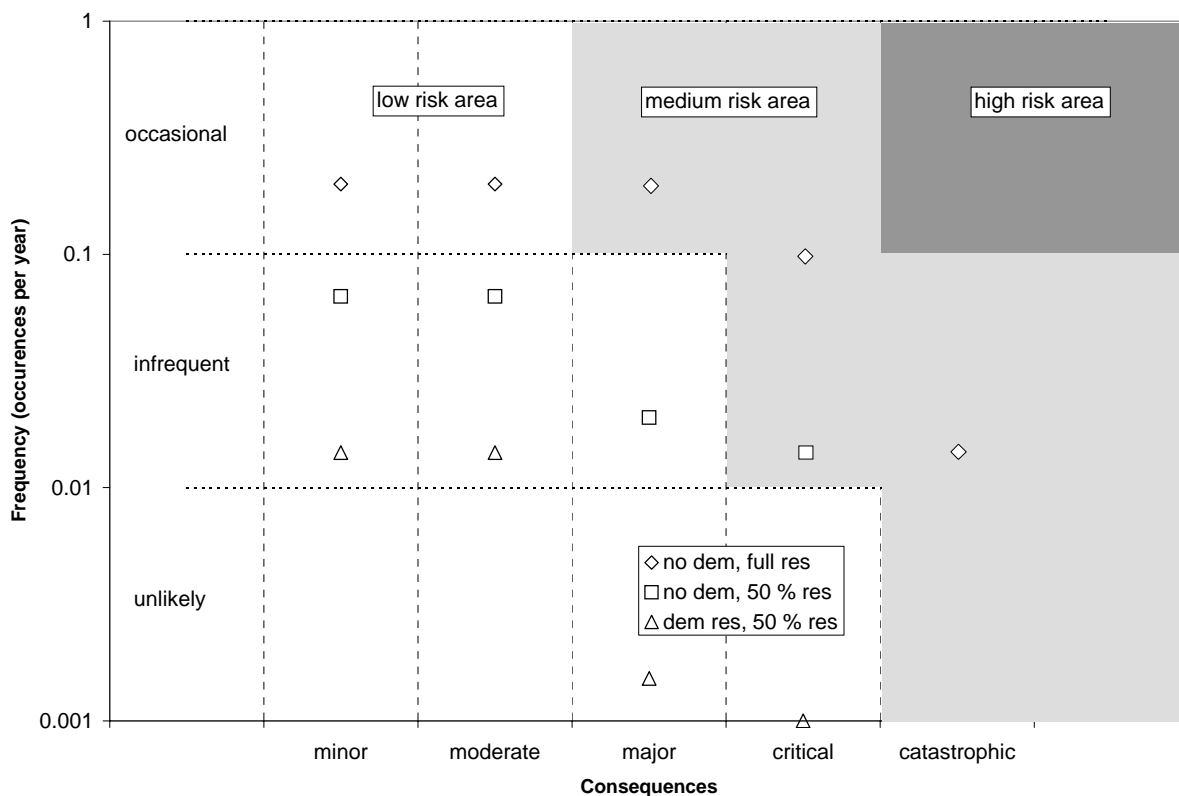


Figure A2-8: Risk graph capacity shortage 2005

The three scenarios are, cf. A2.1.3:

1. No demand side reserves, full reserve requirements (diamonds)
2. No demand side reserves, 50 % reserve requirements (squares)
3. Demand side reserves, 50 % reserve requirements (triangles)

In the latter case, total Nordic reserves in the generation system appear to be 750 MW, close to the limit of 600 MW.

The interpretation of a point in e.g. the infrequent probability / minor consequence square is that the probability of an event with *at least* minor consequences is between once every 10 and once every 100 years.

If it would be assumed that demand is curtailed whenever fast reserve levels drop below the Nordel recommendations, amounting to 4400 MW, the system would be in a medium risk state. This is the scenario given by the diamonds (“no dem, full res”). As discussed earlier, this is an unrealistically pessimistic assumption. However, if fast reserves are strictly kept out of the spot market (as they are to a large extent), cf. the discussion in Section A2.1.3, this result indicates the probability that the spot market might not clear, which is estimated to once every 5 years. On the other hand, if it is assumed that there are considerable demand side reserves *and* that the reserve levels may drop to 50 % of the requirements before load is curtailed (the triangles in the figure, “dem res, 50 % res”), the system appears to be in the low risk area. This implies that fast generation reserves

drop to 750 MW, only slightly higher than the 600 MW agreed within Nordel. It must be emphasized that this is a critical situation with respect to system security, even though curtailment is avoided. The second scenario is a kind of compromise between these: it is assumed that there are not demand side reserves, but that generation reserves can drop to 50 % of the requirements before load is curtailed. Alternatively this can be interpreted as a scenario where approximately 2000 MW of demand side reserves is available, which would give the same result in the risk graph, but a considerably improved system security. In this case the system is basically in a low risk state, although the probability of critical consequences is slightly too high (once every 70 years). This situation occurs in the case of extreme demand, combined with low import capability and/or reduced hydro and nuclear availability.

We now discuss in some more detail the results for the second scenario, assumed to be most realistic in terms of the capacity balance, given the fact that presently 2075 of demand side reserves are contracted by the TSOs ([32], Appendix 1).

Under the assumption of scenario 2, a *normal winter peak* will have a positive capacity balance for all outcomes, also with reduce imports, low hydro availability and one nuclear unit out of operation. Sweden has to import around 500 MW in the case of low hydro availability and one nuclear unit on outage, and Finland 650 MW for all scenarios. Denmark and Norway have a considerable positive balance for all outcomes. On balance, there is no need for import to the Nordic countries for any of the outcomes.

In the case of a *cold winter*, the Nordic countries have a need for imports exceeding the assumed realistic import capability of 2500 MW in the case of low hydro availability. With reduced availability of import, this capability will even be exceeded with normal hydro availability together with unavailability of one nuclear unit. However, the need for import never exceeds *physical* import availability. Sweden has the greatest deficit, varying between 1200 and 2500 MW, Finland about 1000 MW. Norway has a deficit of 700 MW in the case of low hydro availability, but a small surplus otherwise. Denmark has more than 900 MW surplus. The worst case has an expected Nordic deficit of 2082 MW, an average curtailment time of 8.8 hours and 18 GWh of energy not served, representing moderate consequences. Curtailment will primarily have to take place in Sweden and Finland, and possibly to some extent in Norway.

In the case of an *extreme winter*, the need for import to the Nordic countries exceeds assumed realistic import for all outcomes. Unless normal availability of hydro, the need for import will exceed physical import capability. In this case Sweden has a deficit of 2700-4000 MW, and Norway from 300-1100 MW. For Finland and Denmark the situation is the same as for a cold winter. The worst case scenario has a Nordic deficit of 4000 MW, an average curtailment duration of 15.5 hours and an estimated energy not served of 62 GWh. The probability of this scenario is however extremely small. Consequences fall in the minor or moderate classes for all outcomes.

Local problems in the South- and North-Western part have a higher probability of occurring than in other parts of the system. This is discussed in some more detail in the next Section.

With respect to a late spring start, we make the assumption that 1000 MW would be available as import to Norway and 1500 MW to Sweden. Extreme load in this period is further estimated to 19000 MW for Norway and 21000 MW for Sweden. This is somewhat higher than the maximum in Figure A2-6, but that figure was based on data for 1996-2002. Demand has increased since, and moreover 7 years is a short period to estimate extreme values. Under these assumptions and otherwise the same assumptions as described earlier, the availability of hydro power must exceed 70 % of available capacity in Norway and 41 % in Sweden to avoid involuntary load shedding with full reserve requirements. In absolute numbers this means that about 19400 MW of hydro power must be available in Norway and 6500 MW in Sweden to cover unusually high demand in this period. In most years this is probably not a problem, but if such a situation should occur in a dry year with very low reservoir levels at the end of the winter this may evolve in a serious problem, which should be analyzed in more detail.

Although the possibility of physical curtailment due to deficit in generation capacity in 2005 cannot be ruled out completely, the probability is quite small. The occurrence of events with at least minor to major consequences is infrequent. The occurrence of events with critical consequences is in the lower infrequent area. In this analysis demand elasticity is probably underestimated. Concluding, the vulnerability of the Nordic power system with respect capacity shortage is at an acceptable level in 2005, but continuous attention is needed to make sure that it stays in this state.

### **A2.3 Vulnerability for capacity shortage, future system, 2010**

Figure A2-9 shows the risk graph for capacity shortage in 2010.

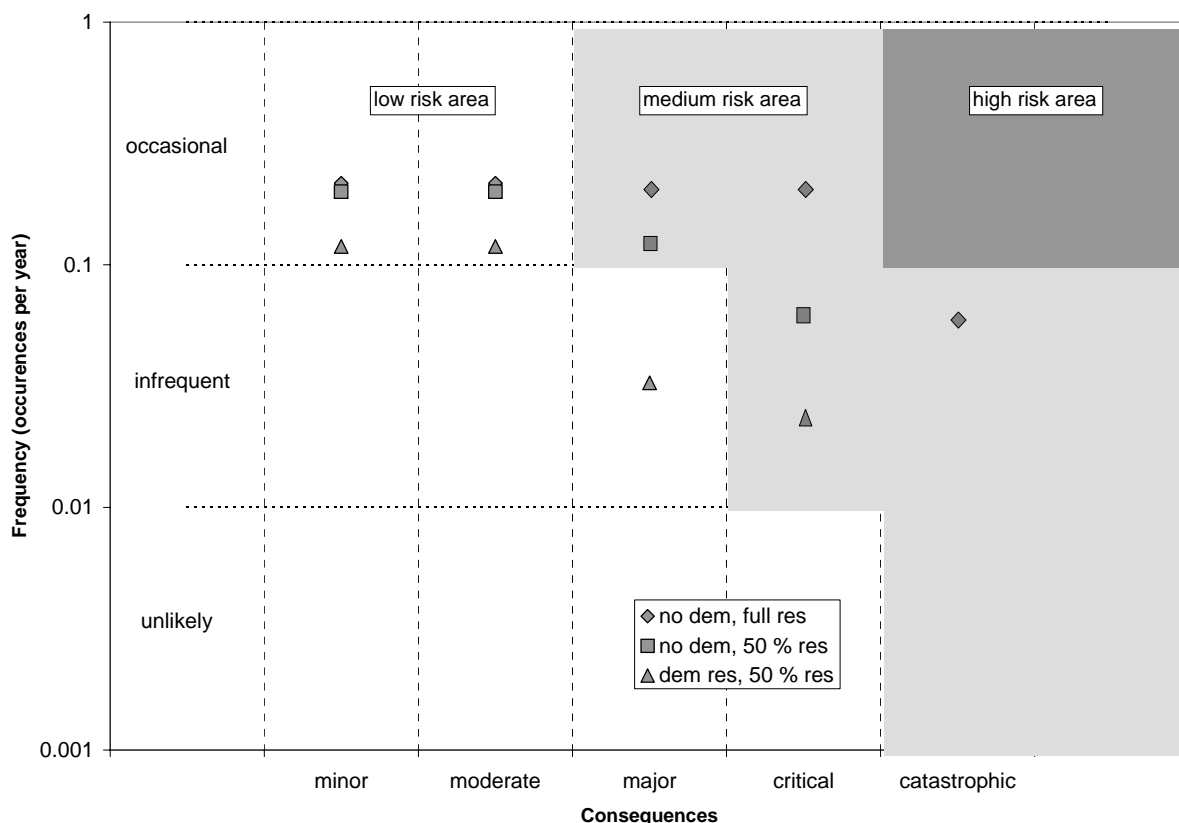


Figure A2-9: Risk graph capacity shortage 2010

The scenarios are the same as for 2005. The risk situation deteriorates between 2005 and 2010. The probability of the spot market failing to clear (illustrated by the black diamonds) is estimated to 0.22, between once every four and once every five years.

Looking at the most representative scenario (the black squares), the probability of minor and moderate consequences is still within the occasional range, but the probability of major consequences also comes in this area. The probability of critical consequences is now estimated to once every 17 years. These are typically situations with a deficit of ~3000 MW, lasting for 5-10 hours during (assumed) two days. The main reason for the severity of the consequences is the flat day-time demand profile in the Nordic countries. This implies that when there is a shortage of several thousand MW, this will involve many hours of load shedding and a correspondingly high level of curtailed energy. As for the analysis of the present system, demand elasticity is probably underestimated, improving the real situation to some extent. But even with optimistic assumptions regarding the utilization of reserves, the system is in a medium risk state.

Under the assumption of this most representative scenario, a *normal winter peak* will have a positive capacity balance for all outcomes also in 2010. Sweden has a negative balance between 500 and 1800 MW and Finland of 300 MW. Norway and Denmark have a positive balance for all outcomes. As a whole, the Nordic area will have a generation surplus for most outcomes.

In the case of a *cold winter peak*, the need for import to the Nordic area exceeds assumed realistic import for all outcomes. The deficit is about 200 MW for the most favourable outcome, increasing to 4300 MW in the worst case. Sweden has a deficit between 2500 and 4000 MW and Finland of 700 MW. Norway has a small surplus with normal hydro conditions, but a deficit of 700 MW with low hydro conditions. Denmark has a surplus of 400 MW. The worst case results in a curtailment of 3700 MW with an average duration of 14.3 hours and energy not served of 53 GWh, which is still a moderate curtailment case according to our classification. For the other outcomes the consequences are minor of moderate.

An *extreme winter peak* would be problematic in 2010. For all outcomes the need for import would exceed physical import capacity. Sweden would have a deficit between 4000 and 5500 MW, Norway between 300 and 1100 MW and Finland of 700 MW, while Denmark would have a surplus of 400 MW. Worst-case curtailment is 5600 MW with an average duration of 18.4 hours and energy not served of 102 GWh, which is classified as a major consequence. Also several of the other outcomes have major consequences, while the remaining have moderate consequences. Still, the probability of such outcomes is quite low also in 2010.

The deterioration of the capacity balance between 2005 and 2010 is caused by the fact that the major share of new resources (gas, nuclear, wind) consist of base load options, contributing less to peak generation than to energy supply.

If no gas plants are built in Norway and the commissioning of the nuclear plant in Finland is delayed (or alternatively, shortly before commissioning of these plants). This assumes that peak demand is unaffected, which is probably somewhat unreasonable because prices would rise considerably in such a scenario and depress demand.

The local problems in the South- and North-Western parts of Norway increase substantially towards 2010 if no gas plants are built without major reinforcement of the grid. However, it is unrealistic to assume that no action would be taken by Statnett before this time. This issue is discussed further in the next Chapter.

With respect to a late spring start, we make the same assumptions as in 2005, but increase the estimates of extreme demand in this period to 20200 MW for Norway and 21700 MW for Sweden, using the same growth between 2005 and 2010 as for winter peak demand. In this case the availability of hydro power must exceed 70 % of available capacity in Norway and 47 % in Sweden to avoid involuntary load shedding with full reserve requirements. In absolute numbers this means that about 19800 MW of hydro power must be available in Norway and 7500 MW in Sweden to cover unusually high demand in this period. Thus for Norway the situation does not change between 2005 and 2010, while it deteriorates for Sweden. Like for 2005 it is difficult to quantify the risk of this situation without further analysis.

Concluding, the vulnerability of the Nordic power system is in the medium risk area, and actions should be evaluated to reduce the risk.



## APPENDIX 3 POWER SYSTEM FAILURES

### A3.1 Introduction

Registration and reporting of disturbances and faults in the Nordic power system are done systematically in all the Nordic countries, but there are differences in how the disturbances are registered. The status for this work and a summary of disturbance statistics can be found in [33]. The statistics for Norway show that the total energy not supplied due to disturbances is on average about 20 GWh per year. This includes *all* disturbances, also in distribution networks, which normally are responsible for the major share of disturbances resulting in load shedding. The corresponding numbers for Sweden, Denmark and Finland are not available, but considering the available statistics on average failure rates and duration of failures, there is reason to believe that power system failures leading to customer interruptions, add up to at least 50 GWh per year. Using 5250 €/MWh as an average cost of energy not supplied (average for Sweden according to [34]), this amounts to annual interruption costs of 263 million Euros. This is a very conservative estimate as costs related to short interruptions and voltage dips are not included. As a comparison, SINTEF Energy Research [35] has estimated the total annual interruption costs for Norway to be in the order of 235-260 million Euros.

Compared with these numbers, the major power system blackout in Southern Sweden and Eastern Denmark 23. September 2003 resulted in approximately 18 GWh of energy not supplied. If 5250 €/MWh is used as an estimate of the specific interruption cost also in this case, the total cost of this incident was 94 million Euros.

These figures are very approximate, and there are of course other factors that make disturbances and blackouts more or less acceptable. It is nevertheless interesting to know when starting the assessment of vulnerability due to power system failures, whether it is the sum of all the small disturbances or the very few large blackouts that imply the highest cost on society?

The simple example above illustrates that the recent blackout in Sweden and Denmark will make considerable impact on the failure statistics for 2003 in terms of power interrupted and energy not supplied. On the other hand, if assuming that blackouts of this size happen once every 20 years, it seems rather clear that the pure economic impact of such events is minor. This suggests that if the large disturbances were to constitute a major part of the total power system disturbances, they would have to occur much more frequently than they have done in the past. This is not to conclude that the power system is not vulnerable to power system failures, but it indicates that the risk of large area power system blackouts in the past has been low because of their low frequency of occurrence.

A main objective in this chapter is to provide an analysis of how the present and the future power system is or will be exposed to risk of power system failures. Section A3.2 describes the approach and the methods that are used in the analysis, with references to the main report. Section A3.3 discusses some important incidents and blackouts in the past in the context of risk level and vul-

nerability. Section A3.4 and A3.5 present the vulnerability analysis of the present and future power system, respectively.

### **A3.2 Approach to the analysis**

The overall approach and methods to be used in the vulnerability analysis are described in Chapter 2 of the main report. The purpose of this section is to provide more specific details regarding the analysis of power system failures. The main objectives of the vulnerability analysis and the key definitions that are used in the report are described in Chapter 1 of the main report.

#### **A3.2.1 Power system security criteria**

The risk of power system interruptions and blackouts is, among others, closely related to operational procedures and standards. The basis for this is the Nordel agreement on system operation [41], which includes definitions regarding power system security criteria and operating reserve requirements. A summary of the main criteria and principles are included here as a reference for the analysis below.

##### ***Single failure criterion (N-1)***

The power system security criteria in Nordel are based on the N-1 criterion, and the following interpretations apply:

- A single failure (e.g. loss of generator, line or transformer, one short circuit fault) in a sub-system shall not result in serious operational disturbances in adjacent sub-systems.
- There shall be an adequate disturbance reserve and transmission capacity to enable the Nordic power system to withstand design contingencies (one design contingency being loss of the largest power plant, i.e. 1200 MW of generation).
- The loss of a busbar in one sub-system shall not lead to serious operational disturbances in other sub-systems.
- Following a disturbance on the N-1 level (that brings the system to an alert state), the system shall within 15 minutes resume operation within normal state. Fast reserves shall within 15 minutes have replaced the spinning reserves used to bring the frequency and voltage within normal limits (done within 30 seconds).
- System protection schemes (SPS) are accepted as part of the N-1 criterion. System protection schemes such as automatic generator tripping or load shedding are used to a variable degree in Nordic countries as a means to increase transfer limits. This requires that the reliability of the SPS is equally high as the primary protection equipment.
- Temporary deviations from the N-1 criterion is to a variable degree accepted regionally by each TSO under special operating conditions, e.g. when important lines or generators are out for maintenance. A normal condition for accepting operation at N-0 level is that the consequence of a critical contingency is clearly limited to a smaller area or sub-system, and that the

expected interruption costs are considerably lower than the cost of preventive actions (regulating power) to enforce N-1 security.

### ***Reserve requirements***

The security criteria above require that various operating reserves are available. Operations are based on the following reserve requirements:

- Momentary (on-line) reserves:
  - A minimum of 600 MW frequency control reserves, fully activated at 49.9 HZ
  - A minimum of 1000 MW instantaneous disturbance reserves. This shall be activated from 49.9 Hz and be fully activated at 49.5 Hz.
- Fast active reserves (that can be activated within 15 minutes).
- Slow active reserves (that can be activated within 4-8 hours).
- Reactive reserves

For complete definitions of the various reserves and requirements, cf. [41].

### ***Vulnerable situations***

One importance of the security criteria in relation to the vulnerability analysis is that a single fault, even if it is outage of the largest generator or the most important transmission line, should in theory never lead to unacceptable consequences. However, in a real-time situation it is not always possible to know if the system is operating in accordance with the N-1 criterion. There are two reasons for this:

- The difficulty of monitoring and knowing the exact operating condition as the loads are continuously changing. This requires very good measurements or state estimators together with precise information systems.
- The problem of identifying and taking into account all single failures that may lead to problems. The reports from the 2003 disturbances in USA/Canada and in Italy conclude that in both cases the systems in fact were violating N-1 security prior to the blackouts.

The focus in this study is on possible situations that can be caused by combination of faults and from combination of faults and other unfavourable operating condition such as extreme loads and lack of reserves. Other contributing factors include human errors such as mistakes during maintenance work or lack of actions from operators. Problems with detecting faults or a critical situation, communication problems among operators, or too slow corrective actions are examples of factors that may contribute to a system blackout.

## **A3.2.2 Event tree**

The initiating events and the possible combinations of faults and adverse conditions that can lead to a blackout are illustrated in the event tree below. The purpose of this diagram (Figure A3-1) is to help structure the various events and the relation between the events that lead to a certain type of blackout.

This approach can be further developed into a formal methodology for analysing probabilities and risk of blackouts. In the vulnerability analysis below the event tree is used primarily to describe possible scenarios and to identify very roughly the probability of the scenarios.

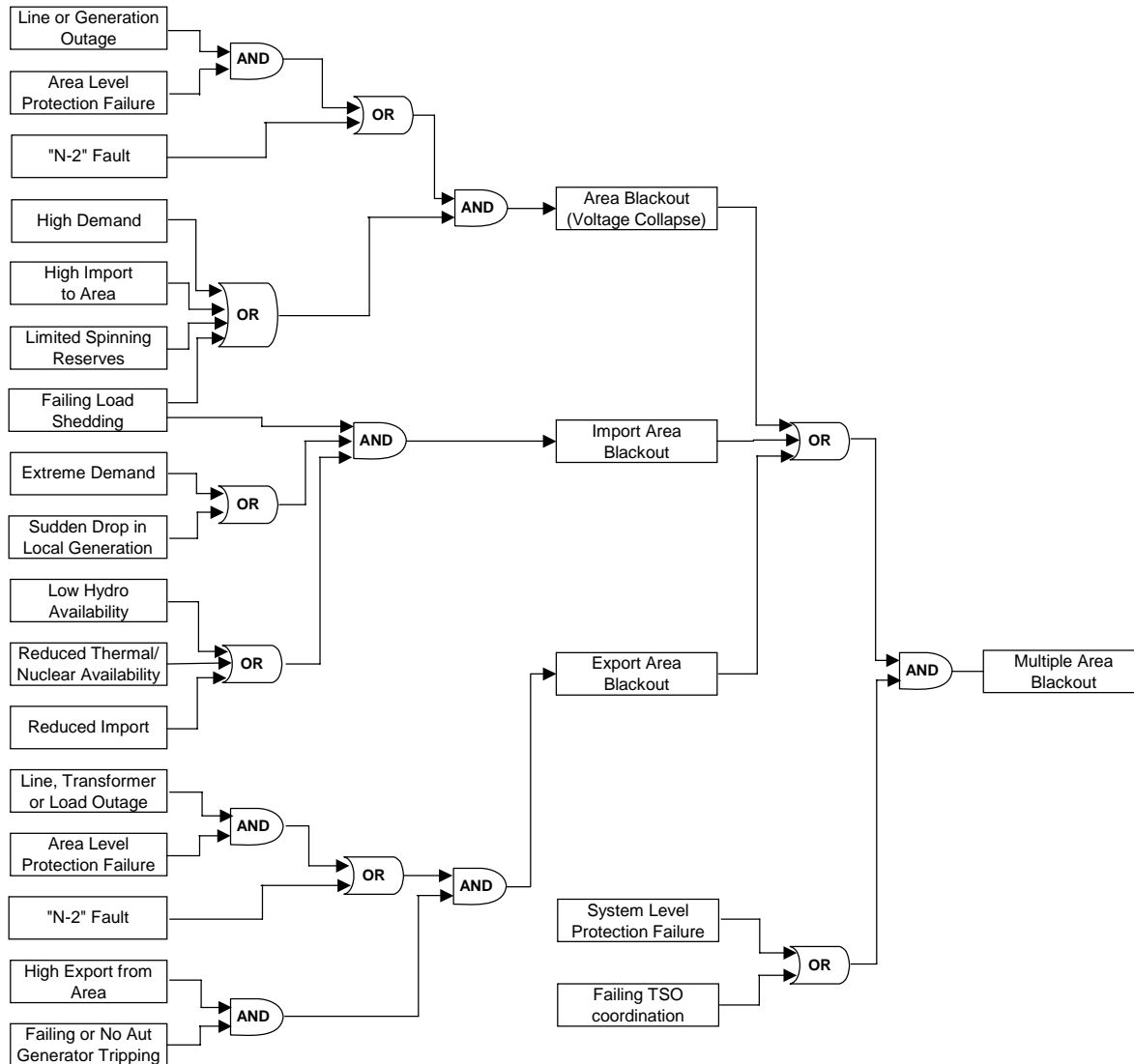


Figure A3-1: Event tree for power system blackouts

A blackout is related to either a generation capacity shortage or unplanned outages of generation, transmission or load. An energy shortage situation can change the probability of a blackout (in either direction), but does not in itself cause a blackout. The system state model in Figure A3-2 is commonly used when discussing power system security and the nature of a system blackout.

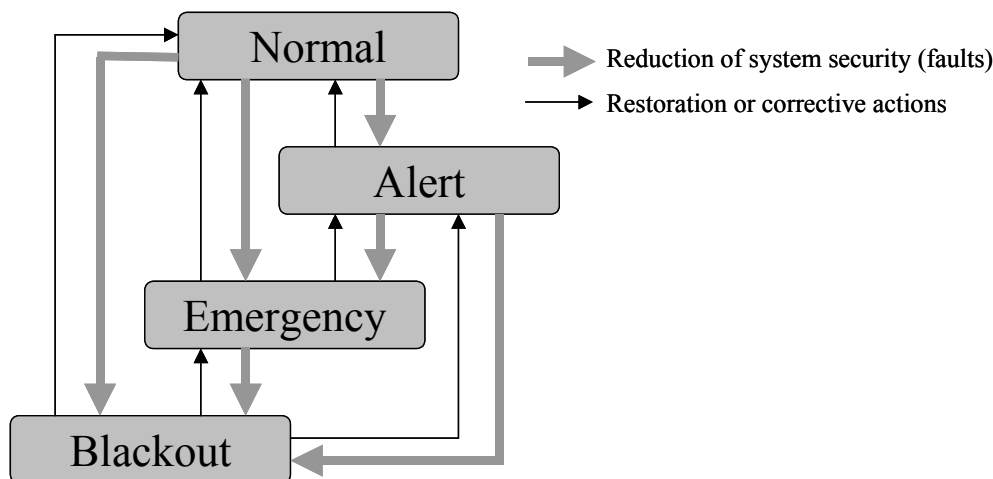


Figure A3-2: System state model

### Initiating events

Outage of a single line or generator should not lead to a blackout. According to the N-1 criterion, it should not even lead to loss of load. However, the system enters an alert state, and combined with failures of the protection system or e.g. mistakes during maintenance a more severe situation (emergency) can occur. It should also be noted that the N-1 is not 100% safe in operation. Operators may think they meet the N-1 criterion but do not, either due to poor maintenance (e.g. trees that cause lines to trip below normal loading limits) or lack of information in the control centre. Alternatively, a severe situation can be caused by the outage of a whole transmission corridor, e.g. in a situation of severe weather conditions. Two or more (independent) outages or faults within a short period of time can also cause an emergency situation. In the event tree this is denoted N-2 faults.

### Unfavourable conditions

In most cases an emergency situation caused by two independent faults will not lead to a blackout. This depends to a large degree on the operating conditions and to what extent the system is stressed. In the event tree we have identified a number of unfavourable conditions, such as “high demand”, “failing system protection” or “high import or export”, meaning that a transmission corridor is loaded to its limit. Unfavourable conditions increase the probability of a system entering an emergency or blackout state.

### Blackout scenarios

In the event tree we have distinguished between three basically different set of events that can lead to a sub-system blackout. The upper part of the figure describes events or combinations of events that can lead to blackout of areas with low generation and high load (import areas). It is indicated that such situations very often end in a voltage collapse, in particular this is the case if there is no protection to shed load or to separate the deficit area from the remaining system in the emergency situation.

Another potential cause of a blackout is related to the same combination of high demand and other factors as discussed in relation with the other event trees shown in Chapter 2 of the main report.

Reserves are at their minimum when all generation and all flexible demand options are utilized. If generation still does not cover demand, the only remaining solution may be to switch off demand involuntary. If this fails, the same sequence of events as discussed above may result.

The third scenario for area blackouts considers areas or sub-systems that operate at light load but with high generation, implying that there is a major power export from the area. It is recognized that under such conditions the power system is often less stable and more prone to power oscillations than when operating in a more balanced condition. When the transfer capacity is weakened by faults or outages, possibly combined with loss of load that further increases power transfer, this may lead to undamped power oscillations that can cause a system breakdown.

#### *Multi-area blackout*

A developing blackout situation can be stopped e.g. if sufficient load (or generation in the export case) is switched off at an early stage, re-establishing a balance between demand and generation. If this has not been planned or does not work, blackout of a major area may result. Blackout of one area can easily cascade in blackouts of several areas as shown among others by the blackouts in the US, and South-Sweden and Denmark in 2003. The consequences can be limited by a combination of sound system protection and well-functioning cooperation between the TSOs that are involved. In the opposite case, multiple area blackouts will result.

The blackout scenarios illustrated in the event tree above must be viewed as a simplified description of events and consequences. It is not necessarily so that a low generation/high load area leads to voltage collapse and a high generation/low load area leads to dynamic instability. The basic problem is that high transfer between areas stresses the system. When the system fails, it will separate into areas ("islands"). Some of the areas will survive and others not. The separation is sometimes intentional and sometimes an unplanned beneficial side effect of fault protection. Whether a particular area goes black as a result of voltage collapse or stability depends on many other factors than the load/generation imbalance.

Furthermore, it is not so that a single area blackout can always be confined to a single area by "well-functioning cooperation between the TSOs". During the initial stages of a blackout that progresses slowly, with time frames of tens of minutes to a few hours, cooperation can avoid any blackout or reduce a potential blackout to minor curtailment, but once the transient that causes an area blackout starts, the process is too fast for human intervention.

### **A3.2.3 Probability of events**

The probabilities of blackout scenarios are expressed as frequencies and ranked according to how often the situations are assumed to occur, as shown in Chapter 2.5 of the main report. The probability of occurrence of each scenario is quantified as far as possible based on the chains of causes described by the event tree. The quantification is based on sources such as disturbance and fault statistics from the Nordic countries (Nordel) when available. Otherwise, it is based on experiences and expert evaluations (qualitative judgements).

#### *N-1 events*

As an example of a simple judgement we can assume that a single fault or outage in the transmission grid (within a given area) happens more than once a year. Thus, single (initiating) N-1 events are typically classified as *probable*. In larger or especially exposed areas there may even be more than 10 faults, characterising the event as *frequent*.

#### *N-2 events*

Only a fraction of the single failures develop into an emergency situation due to protection failures or cascading outages. However, this type of events are more likely to happen than two basically independent failures within a time frame of minutes. Both are typically *occasional* events.

#### *N-k events*

Three independent failures or an N-2 event in combination with stressed operating conditions or adverse weather will typically be considered *infrequent* events. More than three independent critical failures would typically be results of extreme weather conditions or other external threats. Such *unlikely events* are considered out of scope in this analysis.

### **A3.2.4 Geographical areas**

Due to the regional and national differences in structure of the power system as well as the location of generation the impact of electricity supply deficiencies varies between different areas or parts of the Nordic countries. The consequence evaluation is therefore carried out for different geographical areas, determined by the topology, transmission capacities, bottlenecks etc. The chosen areas are as follows:

- Finland, import case
- Finland, export case
- Helsinki area
- Northern Sweden
- Southern Sweden
- Gothenburg area
- Stockholm area
- Eastern Denmark and Copenhagen
- Western Denmark
- Southern Norway and Oslo
- Western Norway and Bergen area
- Stavanger area
- Southern Scandinavia

These areas are of different size measured for instance in terms of number of inhabitants or demand in MWh. The choice is based on evaluations regarding regions or areas assumed to be of interest at a Nordic level as well as the electrical topology and previous analyses of the Nordic

power system. The study will also to some extent look at smaller areas where the probability or duration of a blackout situation might be critical.

### **A3.3 Analysis of previous incidents**

This section includes a short description of the most recent and most extensive blackouts in the Nordic power system. The point is not to analyse the various incidents (for that we refer to the official reports and descriptions of the various events), but rather to assess the incidents in terms of risk. The motivation for this is to demonstrate the chosen methodology for risk analysis, and since there have been various blackout situations affecting the Nordic countries during the last year, these incidents will form an important basis for the analysis of the present system.

The main goal of this section is to discuss the probability of blackouts based on the experiences from the past incidents. Together with the documented consequences, this enables us to present the events in the diagrams for consequence assessment (cf. Figure 2-11) and risk analysis (cf. Figure 2-12). The findings will be used to support the analysis of the present system.

#### **A3.3.1 Sweden 1983**

This is the oldest incident included in this discussion, but still important because it represents the largest single blackout that has occurred in the Nordic countries [36].

The blackout happened early afternoon on 27 December 27 and affected most of Southern Sweden south of *Interface 2* and some other local areas<sup>21</sup>. Interface 2 is the main corridor of power transfer from mid to south of Sweden, approximately on the 61-degree latitude. The corridor includes seven 400 kV transmission lines, and prior to the event the power flow north to south on Interface 2 was 5600 MW, which was well within the transfer limit at that time.

Prior to the event, at 12:20, unit 1 in Oskarshamn tripped, and 490 MW of generation in the south was lost. This caused an increase in the transfer from north to south, but the power flow on Interface 2 was still within its allowable limits.

The blackout was initiated at 12:57 after a breakdown of a disconnector in Hamra transformer station (one of the main stations feeding Stockholm city). The breakdown caused tripping of all lines connecting to the station, including two of the seven 400 kV lines of Interface 2. The weakening of the grid caused overload on the remaining lines and voltage drops in the southern parts of the network. As load recovered after the initial voltage drops, the overloading became increas-

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<sup>21</sup> We have chosen to use the word “interface” as the English translation of “snitt”, which is the commonly used term in Scandinavian languages to describe a set of transmission lines (or transformers) that carry the main power transfer between two areas. Thus, Snitt 2 in Sweden is translated to Interface 2. Other terms that are used in English literature are “Power Transmission Corridors” or “Transfer Paths”.



ingly severe. This led to cascading outages of the transmission lines in the interface and eventually to separation of Southern Sweden south of Interface 2. After the separation, Southern Sweden had lost 7000 MW of import, and the consequence was a total voltage collapse.

The power interrupted in Sweden was 11400 MW, and the energy not supplied was estimated to 24000 MWh. Restoration of the power supply appears to have been fairly efficient with an average outage time of 2.1 hour. There were also consequences of the event in Eastern Denmark: Three main power plants tripped due to low voltages before all the cables to Sweden tripped as a result of power oscillations. Approximately 520 MW of consumption was lost, partly disconnected by the automatic under-frequency load shedding and partly by manual disconnection. The total energy not supplied in eastern Denmark was estimated to 765 MWh.

Using the classification of Figure 2-11, this is a *critical* event. It is, however, difficult to assess the probability of an event like this. The blackout was basically initiated by a single failure, the breakdown of a disconnect, but the series of events (from the problem was discovered, to the start-up of initial repair work and finally to the disconnection of the entire station) have a much lower probability than an N-1 event. Taking into account the high focus on reliability in design of transformer stations and switchgear since this event, we have judged it to be *infrequent* (assuming a probability of occurrence once every 20-30 years).

### **A3.3.2 Helsinki 2003**

This incident happened in the afternoon of Saturday 23 August. The initiating event was a short circuit that happened by a mistake during connection of a generator that had been out for maintenance. The primary protection failed to correctly isolate this fault, and as a result several lines tripped, among them two of the main lines feeding the Helsinki and Vantaa area.

Around 800.000 people were affected and approximately 500 MW power was interrupted. The main transmission grid was reconnected within 15 minutes and all consumers had power restored within one hour.

All circumstances taken into account, this is classified as a *minor* event with probability *occasional*. The blackout was a result of a short circuit fault (caused by a human error) and a protection failure. This is a N-2 event, and we have assumed the probability of occurrence to be once every 8-10 year.

### **A3.3.3 Southern Sweden/Eastern Denmark 2003**

This incident happened early in the afternoon of Tuesday 23 September [37], [38]. The cause of the blackout and series of events have many things in common with the 1983 blackout described above:

Prior to the event the operating conditions were quite normal. At 12:30, generator 3 in Oskarshamn was stopped due to an internal fault and nearly 1200 MW of generation in the south was lost. This led to increasing power transfer from Norway and Northern Sweden, and the state of the power system operation changed to alert.

Five minutes later the blackout was initiated by a short circuit fault in a disconnector at the main transformer station in Horred (close to the town of Varberg). The fault caused a total breakdown of the disconnector, which during the breakdown hit the opposite bus-bar. Then, both main bus-bars were short circuited and all lines connecting to the station were tripped. As a consequence, two units in Ringhals that are feeding in to Horred tripped and additionally 1800 MW of generation was lost. The weakening of the grid and the loss of 3000 MW generation in Southern Sweden caused power oscillations and decreasing voltages. After less than two minutes the system separated and collapsed south of Gothenburg. Eastern Denmark that at the time was exporting power to Sweden did not separate and went down in the same collapse.

The power interrupted was (totally in Sweden and Denmark) 6550 MW and the energy not supplied is estimated to 18000 MWh. The restoration of the power system went fairly quickly in Sweden with an average outage time of 2.1 hour. Restoration was more difficult in Denmark, with an average outage time of 4.3 hours. In total the average outage time was 2 hours 45 minutes.

Using the classification of Figure 2-11, this is on the border between a major and a critical event. Taking other factors into account, such as the time of year and the amount of severe damages<sup>22</sup> caused by the blackout, we judge it to be a *major* event. As for the 1983 blackout it is difficult to assess the probability of this event. Svenska Kraftnät concluded in its report that the blackout can be classified as an N-3 event, based on the fact that it was one single failure and one double failure that occurred within five minutes. The double failure consisted of the simultaneous disconnection of two separate bus-bars including the two 900 MW nuclear units connected to each one of them. The disconnection of one of these bus-bars would in itself constitute an N-1 event. Therefore, this is clearly an *infrequent* event (assuming the probability of occurrence to be about one every 30 years).

#### **A3.3.4 Western Norway 2004**

A large part of Western Norway, including Bergen and most of Hordaland, is connected to the rest of the power system through one corridor in the south, the “Sauda interface”, and in the north by one 300 kV line from Fardal towards Evanger. The Sauda interface includes the two 300 kV lines Hylen-Sauda and Nesflaten-Sauda.

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<sup>22</sup> It should be noted, however, that there were damages: One 750 MVA generator step up transformer was destroyed resulting of unavailability of the largest generating unit in Eastern Denmark (Asnæsværket unit 5, 650 MW) for several months.

At 13:59 on Friday 13. February the 300 kV Nesflaten-Sauda split up in a line joint. The line split was at first sensed by the distance protection as a high impedance fault, and therefore the breakers did not disconnect the line immediately. The fault was also seen by the distance protection on the other 300 kV line Hylen-Sauda that also started. As a consequence when the fault current increased, both lines in the corridor were tripped after the time delay of the relays. The remaining connection was now in the north, where the 300 kV line Modal-Evanger experienced a 50% overload. With decreasing voltages and increasing currents, this line also tripped and the whole area (Bergen, larger part of Hordaland and northern parts of Rogaland) collapsed.

A little less than 500.000 people were affected and approximately 2400 MW power was interrupted. The energy not supplied was estimated to nearly 1200 MWh, which means the average duration of the outage was 0.5 hour. Almost all consumers had power restored within one hour. According to the chosen classification, this is a *moderate* event. The event was initiated by one fault, but the blackout was a result of the tripping of two lines. It can therefore be discussed if this is a N-1 or a N-2 event. In any case, this is not a contingency that is included as a single failure in the present operating strategy. This suggests that the probability of this event is *occasional*. Since this is an area with more frequent bottlenecks than in the Helsinki area, we have assumed the probability of occurrence to be once every 5 year.

#### **A3.3.5 Risk assessment**

As a summary and for comparison the four incidents described above are plotted in the consequence diagram in Figure A3-3. In Figure A3-4 the same incidents are plotted in the risk diagram with the probabilities as suggested above.

A simple assessment based on these plots (Table A3-1) indicates that none of the previous blackouts can be considered high-risk events. A main reason for this is the relatively limited consequences of all the incidents, which is mostly due to the fact that the duration of all the blackouts has been reasonably short.

Strong efforts are and should be taken to reduce the probability of critical events as much as possible. This analysis indicates that it is only the 1983 blackout in Sweden that belongs to the medium risk events.

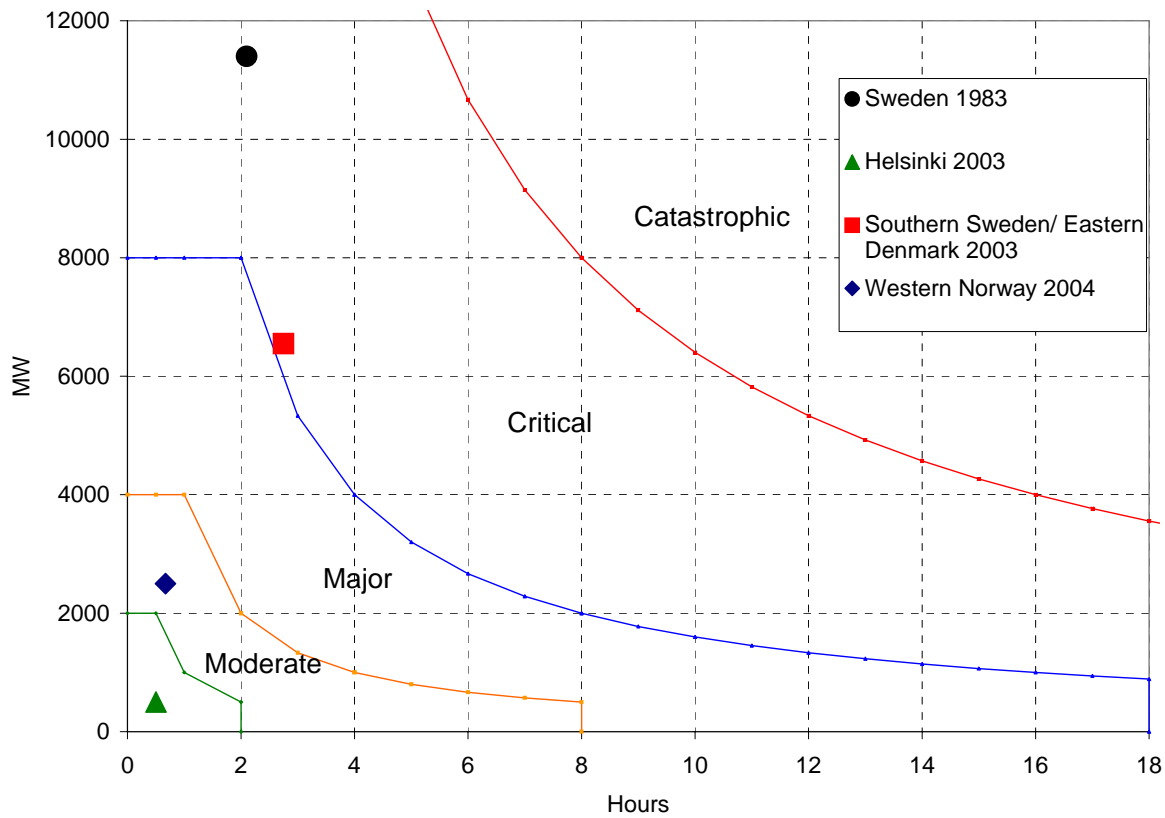


Figure A3-3: Previous incidents in plotted in consequence diagram.

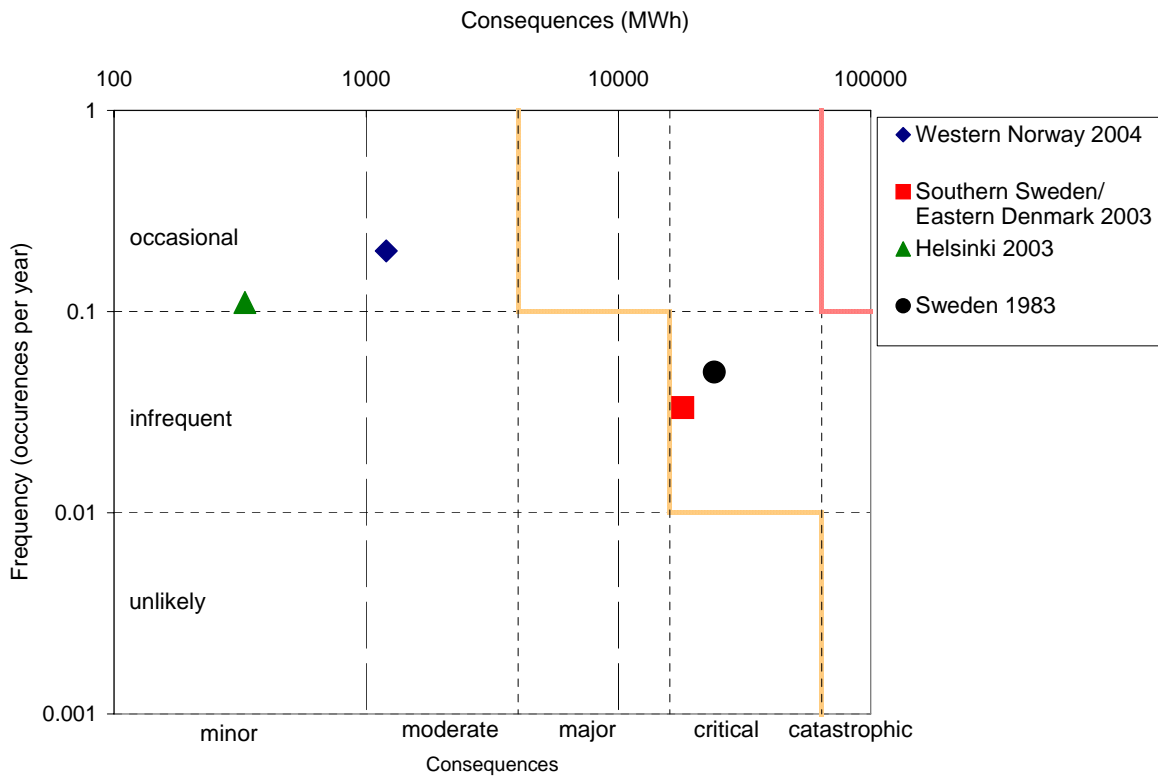


Figure A3-4: Previous incidents in risk diagram.

Table A3-1: Previous incidents summarized in risk matrix

Risk matrix for previous incidents					
Probability	Consequence:				
	Minor	Moderate	Major	Critical	Catastrophic
Frequent					
Probable					
Occasional	Helsinki 2003	W. Norway 2004			
Infrequent			Sweden/Denmark 2003	Sweden 1983	
Very unlikely					

### A3.4 Analysis of present system

This section presents a number of blackout scenarios. The selection of scenarios, their consequences and probabilities are based on various information and sources. The most important sources of information are:

- Experiences and reports from previous events and power system studies.
- Other written material and reports, such as transmission plans and Nordic system plans.
- Discussions with key persons in operation planning at the Nordic TSOs.

The various blackout scenarios are related to certain geographical areas. Each scenario is presented with a description of the critical situations and events that can lead to a blackout, and a discussion of the probability and the consequence involved.

The analysis of the present system will be summarized using the risk matrix as described above. This is used to compare and classify each of the scenarios, and thereby provide a basis for identification of the most vulnerable situations regarding power system failures.

#### A3.4.1 Finland

##### *Scenario 1: High import to Southern Finland*

This scenario assumes high load in Finland and very little generation in the southern parts of Finland. In this situation there will be high power transfers both from Russia and on the interface P1, which include three 400 kV lines from north to south in Finland. The most critical double contingencies are either the loss of the double 400 kV lines Pikkarala-Alajärvi or loss of the parallel lines in Russia feeding towards Vyborg. In extreme situations when both corridors are loaded to their operating limits, this can lead to separation and collapse of southern Finland.

The consequence of this would be that up to 10000 MW power is interrupted, and if assuming that the average outage duration is 3 hours there will be 30000 MWh of energy not supplied. This is a *critical* event.

Regarding the probability of occurrence, this is considered an *infrequent* event that will maximum occur once every 20 years. Based on the above, a blackout in Southern Finland is considered a *medium risk* event.

### ***Scenario 2: High export from Finland***

This scenario assumes light load in Finland and high generation in the southern parts of Finland. In this situation there can be maximum power export to Sweden through the AC connection in the north (1100 MW) and on the FennoSkan HVDC link in the south (550 MW). In this operating condition the transfer limits are determined from stability constraints. The critical contingency in this situation is outage of the FennoSkan link, which will increase power transfer on interface P1 and on the Sweden-Finland interface. If a second line outage occurs, e.g. in P1, this may cause un-damped power oscillations that in the worst case could result in an almost total collapse of the Finnish power grid.

The consequence of this would be that up to 8000 MW power is interrupted, and if assuming that the average outage duration is 4 hours there will be 32000 MWh of energy not supplied. This is a *critical* event.

Regarding probability, this is considered an *infrequent* event that will maximum occur once every 30 years. Based on the above, a blackout in Finland during power export is considered a *medium risk* event.

### ***Scenario 3: Helsinki area blackout***

This scenario assumes that one or more transmission lines supplying the Helsinki area are out of service. In this situation the area cannot withstand a failure causing outage of two or more lines. A double line outage could be the result of two independent failures, or more likely one initiating failure with cascading outages, e.g. due to protection misoperation.

The 2003 blackout in Helsinki gives an indication of the consequence. However, this incident happened on a Saturday afternoon in the early autumn, thus the consequence of this event is characterized as minor. A similar outage during a peak load winter day would in the worst case be a *moderate* event. This is based on the assumption that up to 2000 MW power is interrupted, and that the restoration time will be less than one to two hours, resulting in maximum 2000 MWh energy not supplied. This is in line with the experiences from the previous event indicating that the restoration process was efficient. A blackout in Helsinki would have to last for several hours in order to be major or critical, which is considered unlikely.

The past experiences have also shown that a double line outage is sufficient to cause a blackout in Helsinki. This event is considered *occasional*, with probability of occurrence maximum once every 5-10 years. Based on the above, a blackout in the Helsinki area is considered a low risk event.

### A3.4.2 Sweden

#### ***Scenario 4: Northern Sweden***

This scenario is related to power transmission constraints from Northern Sweden on Interface 1. In situations when the power transfer is at the limit (3000 MW), outages of any two of the four 400 kV transmission lines of Interface 1 could lead to severe stability problems. It is, however, difficult to predict the consequence of this situation, considering also the connections to Finland and Northern Norway.

In this scenario we have assumed that increasing power oscillations lead to separation of the system south of Interface 1. It is also likely that the connection to Norway (Ofoten-Ritsem) will trip. The question is then what will happen with the connection to Finland. If we assume that Finland will separate in the north and stabilize, the power oscillations and imbalance in the north of Sweden will lead to a collapse.

The consequence of a collapse in north of Sweden could be that up to 3000 MW power is interrupted, and if assuming that the average outage duration is 1-2 hours there will be 3-6000 MWh of energy not supplied. This is a *moderate to major* event (depending on the duration).

Regarding probability, this is considered an *infrequent* event that will maximum occur once every 30 years. Based on the above, a blackout in Northern Sweden is considered a *low risk* event.

#### ***Scenario 5: Southern Sweden***

The most severe blackout scenarios affecting southern parts of Sweden are related to Interface 2 being the critical transmission corridor. This was first of all demonstrated by the 1983 blackout as described above. Interface 2 is a strong interconnection with a transfer limit up to 7000 MW. This is also the main problem from a security point of view. When critical failures happen that lead to line outages in this interface and possibly separation of the grid, this will obviously have severe consequences for Southern Sweden. The consequences are also likely to affect Eastern Denmark and in extreme cases also Southern Norway (see scenario 13).

In the scenario where the consequence is a total collapse of Southern Sweden and possibly Eastern Denmark the interrupted power may be up to 15000 MW. When assuming that the average outage time is 3 hours the energy not supplied will be 45000 MWh. This is a *critical* event.

The scenario is most likely to happen in an operating situation with medium to high loads and little generation on-line in south of Sweden. The initiating failures may be multiple line outages, possibly in combination with generator outages in southern Sweden. This will lead to increasing demand for power transfer from the north, and with weakened transmission capacity this will cause overloads, voltage drops and power oscillations that in the worst case may end in a total collapse.

When assessing the probability of this scenario, we have considered that the system must be in a stressed operating condition (maximum power transfer) and at least two of the main 400 kV lines

in the interface must be tripped to cause a blackout in Southern Sweden. Such events are considered *infrequent*, and with probability of occurrence about once every 25 years. Thus, this is a *medium risk* event.

#### ***Scenario 6: Gothenburg area***

Another corridor of concern in Southern Sweden is the “West-coast” interface. This corridor consist of the two 400 kV lines Stenkullen-Strømme and Kilanda-Horred. This interface represents an occasional bottleneck when the power flow is to the north with export to Norway. In a congested situation a double line failure or a single line outage in combination with tripping of one unit in Ringhals will create problems. The problem is related to the limited ramping capability of the thermal power plants in the south. If the interface is tripped there will be an immediate power surplus in the south that will create power oscillations and possibly instability leading to a blackout. The consequence is somewhat uncertain, but the Gothenburg area and a larger part of Southern Sweden may be affected. We have assumed that up to 6000 MW power may be interrupted with a duration of 2-3 hours. This is about 15000 MWh of energy not supplied, which classifies as a *major* event.

This blackout scenario assumes double (N-2) failures in a limited geographical area. We believe this is an *infrequent* event with probability of occurrence about once every 10-15 years. Thus, it is classified as a *low* risk event but very close to being *medium* risk.

#### ***Scenario 7: Stockholm area***

Stockholm is presently a focus area from a security point of view. The main reason for this is two major power outages in the recent years, which both have happened because of fires in a tunnel with two main transmission circuits feeding suburbs.

In the present situation a double line outage can cause outage of up to 4000 MW load in Stockholm. This is a *moderate* to *major* event depending on the restoration time. One hour average outage time is assumed here. Taking into account that network reinforcements have started (“Stockholms Strøm” project), the probability of new blackouts is considered to be occasional, with a frequency of occurrence once every 5-10 years. This puts the scenario on the border between the *low* and *medium* risk category.

### **A3.4.3 Denmark**

#### ***Scenario 8: Eastern Denmark and Copenhagen***

Because of the strong ac connections with Southern Sweden, the risk of a complete blackout in Eastern Denmark is closely related to interface 2 and the problems described in scenario 5. In addition to this a critical contingency for Eastern Denmark is a fault (or combination of faults) that leads to outage of both 400 kV lines/cables to Sweden in a situation with high import. The power deficit following such a failure would lead to extensive customer interruptions. In the best case this could be a partly collapse if the automatic under-frequency load shedding relays work suc-



cessfully and establish a new balance between generation and load. In the worst case this would result in a total collapse in Eastern Denmark.

The consequence of a total blackout would be up to 3000 MW of power interrupted. Assuming 3 hours average restoration time, this amounts to 9000 MWh energy not supplied. This is a *major* event. The probability is assumed to be *infrequent* with a frequency of occurrence once every 10-15 years. This is a *low* risk event.

### ***Scenario 9: Western Denmark***

The power system in Western Denmark is synchronized with the UCTE system, and there is a strong connection (two 400 kV lines and two 220 kV lines) with Germany. The total exchange capacity (in 2005) with Norway and Sweden is 1600 MW on the Skagerrak and Kontiskan HVDC links. To a large degree Western Denmark depends on both the ac connection with Germany and the HVDC connections for provision of momentary and fast reserves. An important characteristic of the power system is also the high share of wind power and distributed generation. To cope with the variability and uncertainty in actual production from these units there has to be reserve capacity on the interconnections.

The risk of widespread blackouts in Western Denmark is thus closely related to operating situations with high import or high export, and in particular situations where few of the large conventional power plants are on-line. It is also likely that the most critical situations arise when there are substantial deviations between production forecast and actual production from wind power. The amount of power transit (between Germany and Norway/Sweden) may also influence the consequence of faults and disturbances.

It is assumed that a total blackout in Western Denmark will only happen if a combination of faults leads to complete separation from Germany in a situation with high import. The probability of such a contingency is very low. A more probable scenario is a blackout in the northern parts of Jutland. In this area, critical faults can lead to stability problems in export situations with surplus wind power. Power oscillations and voltage instabilities can lead to blackouts in several network areas, but the consequences will most likely be limited to the northern parts of Jutland. Alternatively, a critical contingency can be tripping of the Skagerrak HVDC-link with the loss of 1000 MW import in combination with other main line or protection failures. Critical faults in the transmission grid can also lead to outage of large amount of wind power capacity, which will add to the probability of a total collapse.

In the worst case the consequence of a blackout could be up to 3500 MW of power interrupted. Assuming 3-4 hours average restoration time, this amounts to about 12000 MWh energy not supplied. This is a *major* event. The probability is assumed to be *infrequent* with a frequency of occurrence less than one every 15 years. This is a *low* risk event.

#### A3.4.4 Norway

The Norwegian power system is by nature more distributed than other parts of the Nordic system. This is due to the dispersed locations of hydro generation and the long distances between load centers. One consequence of this in terms of power system security is that it may be difficult to enforce N-1 security at all times in the transmission grid. Thus, there are several areas within Norway where the probability of a collapse resulting from a power system failure on the transmission level is considerably higher than what is found in other Nordic countries. On the other hand, the distributed nature of the power system will contribute to limit the consequences (geographical extent) of a blackout. The risk level is therefore in general not higher than in more centralized systems.

The probability of a blackout in such areas may in the worst case be classified as *probable*, but the consequence is most likely *minor*, and therefore the risk is *low*.

In the present analysis, only a few of the current focus areas will be described.

##### ***Scenario 10: Southern Norway and Oslo area***

The main risk of a widespread blackout in Southern Norway is related to situations with high import and low generation in the largest hydro power plants in Western Norway. This typically happens during periods with medium loads.

The most likely blackout scenario assumes maximum import from Sweden on the Hasle interface and from Denmark on the Skagerrak HVDC link. A critical contingency is a fault near Hasle substation, e.g. in combination with a protection system failure or a second independent line outage. This could lead to outage of both lines towards Sweden, which in the best case will result in separation of Southern Norway. The impact of this failure could also trip the Skagerrak link, and the result will be an immediate power deficit of more than 20 % of the load demand. In the best case the primary reserves and the automatic under-frequency load shedding would be able to save parts of the system. In the worst case there would be power oscillations and voltage drops that result in a total collapse of Southern Norway. In the extreme case if Southern Norway fails to separate from Mid-Norway a blackout could also affect parts of Mid-Norway.

The consequence of a total blackout would be up to 15000 MW of power interrupted. Assuming 2 hours average restoration time, this amounts to 30000 MWh energy not supplied. This is a *critical* event. The probability is assumed to be *infrequent* with a frequency of occurrence about once every 20 years. This is a *medium* risk event.

Severe failures and outages relating to the Hasle interface are also a concern in high export situations, but this is considered less critical concerning the risk of a total blackout. It is believed that Southern Norway will stabilize after being isolated in a surplus power situation. However, in combination with other faults the loss of 2000 MW from Norway to Sweden on the Hasle interface could be a problem for Southern Sweden.

***Scenario 11: Western Norway***

In this context Western Norway includes Rogaland to the north of the Sauda interface, Hordaland and partly Sogn og Fjordane. The limited transmission capacity to or from this area as described above (2004 blackout in Western Norway) is the main concern. In a high import situation the system is not able to withstand an outage of any two lines feeding the area. This scenario was clearly demonstrated by the recent blackout in February 2004.

Another critical operating condition is when there is maximum generation in Sogn and the Bergen area with high power export towards east and south. Critical contingencies, e.g. outage of the 300 kV Fardal-Aurland in combination with a second fault, will lead to stability problems and a possible collapse of a larger area.

These scenarios would result in customer interruptions in the range of 2500 MW. Assuming that the average outage time is one hour, this is classified as a *moderate* consequence. In the present situation the probability is judged to be *occasional* with probability of occurrence about once every 5 years. Thus, the risk of this event is *low*.

***Scenario 12: Stavanger area***

The situation for Stavanger is somewhat similar to the Bergen area and Western Norway. The power supply relies on two 300 kV lines from Kielland and Tonstad, respectively that both terminates in Stokkeland substation. A failure that causes outage of both lines will result in a total collapse of the area if the power import is sufficiently high.

In this case the interrupted power could be up to 1000 MW. Assuming that the average outage time is one hour also here, the consequence is on the border between *minor* and *moderate*. The probability is judged to be *occasional* with probability of occurrence about once every 8-10 years. Thus, the risk of this event is *low*.

As indicated above, there are also other areas that experience the same operational security problems as Stavanger and Western Norway. One of these areas is Mid-Norway (southwest of Trondheim). Two transmission lines at 300 kV and above feed the area. Consumption increases due to offshore industry, and there are various plans for generation and transmission expansion. With less than 1000 MW of load, a risk analysis of the present system will put this in the same category as Stavanger.

The same conclusion is drawn for the Finnmark region, an area with very long distances between load centers, and a transmission grid that is basically a long 132 kV connection. Generation is also distributed in Finnmark, but in periods there may be little hydro generation available, and then power system failures may easily lead to collapse of the whole area.

If outage duration becomes very long due to e.g. extreme weather conditions, the consequence of a blackout can be moderate, but normally we would judge the consequence as minor, and thus the risk analysis of the present system will put Finnmark also in the same category as Stavanger.

#### **A3.4.5 Worst case: Southern Scandinavia blackout**

##### ***Scenario 13: Southern Scandinavia***

There is a certain risk that most of Southern Scandinavia would collapse if a number of the unfavorable conditions that are used to describe the scenarios above occur at the same time.

A worst-case scenario assumes a situation with very high power flows from east to west and from north to south. This situation would most likely happen in an operating condition with medium to high loads and with highly reduced hydropower capacity in Southern Norway. At the same time there must be full hydropower capacity available in Sweden and Northern Norway and also maximum power export from Finland.

The initiating faults to cause such a blackout would be related to Interface 2. The situation will be similar to scenario 5 (Southern Sweden), except that cascading outages will also separate the Hasle interface and lead to a collapse in southern Norway as well as in Eastern Denmark.

This could cause power interruptions in the range of 30000 MW. Assuming that the average outage time will be about three hours, and depending on a number of uncertain factors resulting from such an extreme event, the consequence may approach the *catastrophic* category. The probability is judged to be *infrequent* with a frequency of occurrence not more than once every 40-50 years. Thus, the risk of this event is still expected to be *medium*.

### A3.4.6 Risk analysis

A summary of the analysis of the present system is presented in this section. All the 13 blackout scenarios described above are plotted in the consequence diagram in Figure A3-5. In Figure A3-6 the same incidents are plotted in the risk diagram with the probabilities as suggested in the above analysis. Table A3-2 summarizes the present system analysis in the risk matrix.

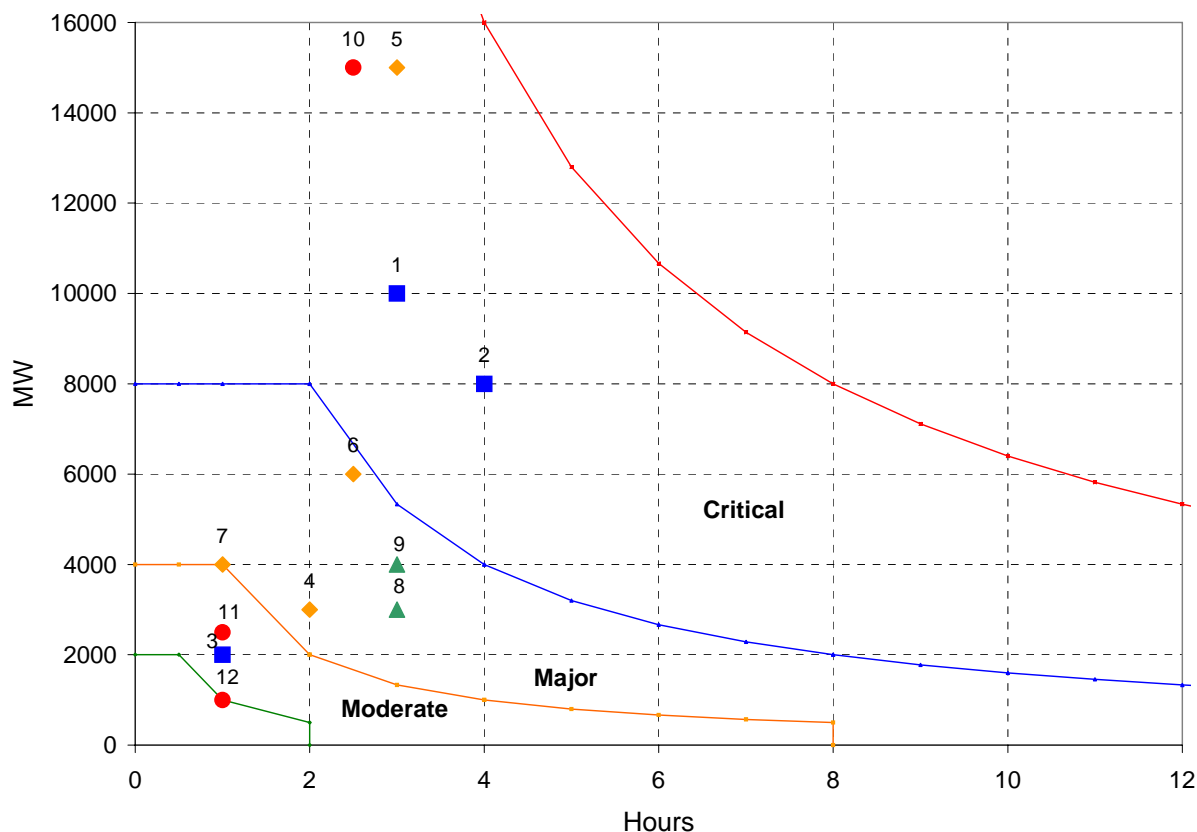


Figure A3-5: Consequence assessment of present system. The numbers refer to the scenarios described above. Blue coloured markers (squares) are used for the Finnish scenarios, orange colours (diamonds) for Sweden, green (triangles) for Denmark and red (circles) for Norway.

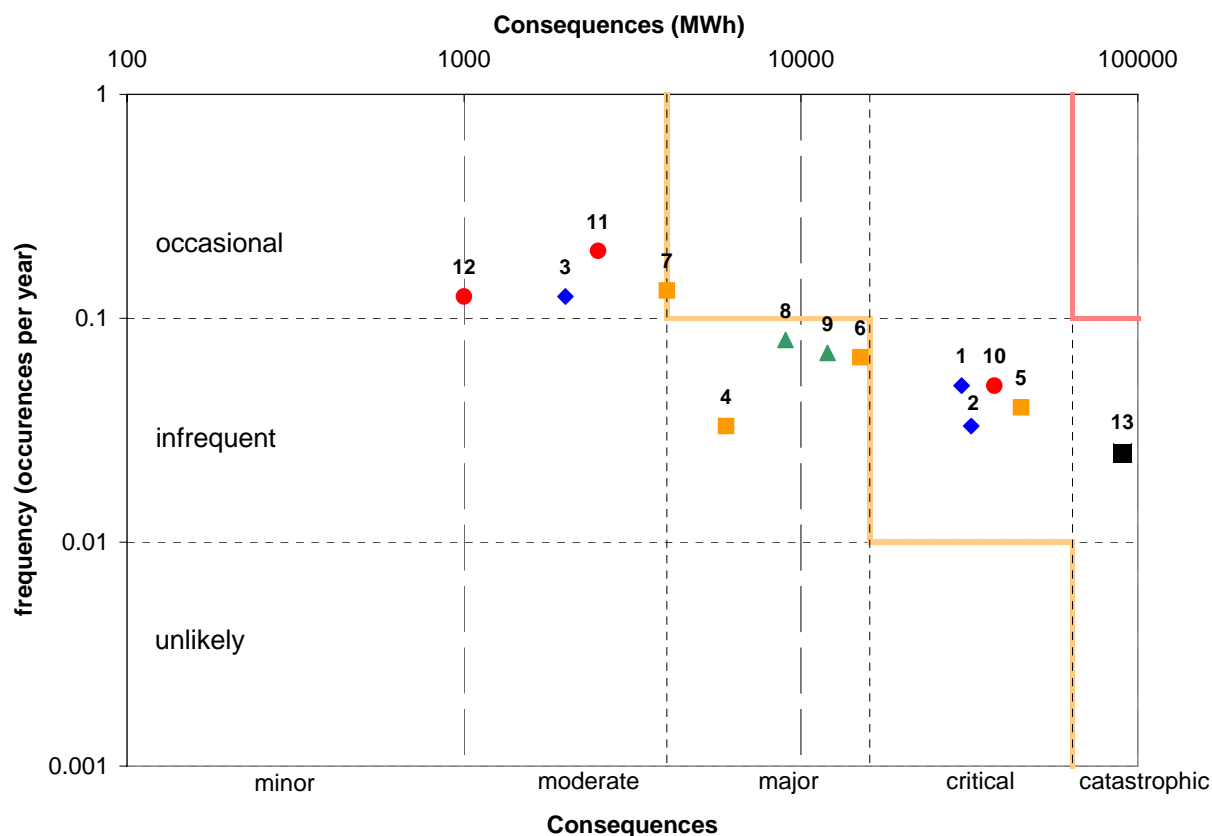


Figure A3-6: Risk analysis for the present system. The numbers refer to the scenarios described above. Blue coloured markers (diamonds) are used for the Finnish scenarios, or orange colours (squares) for Sweden, green (triangles) for Denmark and red (circles) for Norway.

Table A3-2: Present system analysis summarized in risk matrix. The numbers refer to the scenarios above.

Risk matrix for present system					
Probability	Consequence:				
	Minor	Moderate	Major	Critical	Catastrophic
Frequent					
Probable					
Occasional		3,7,11,12			
Infrequent			4,6,8,9	1,2,5,10	13
Very unlikely					

There are five scenarios that can be characterized as critical or worse. All these events are likely to happen infrequently, i.e. with frequency of occurrence less than one per 10 years. Thus, they come in the category *medium risk*. All other scenarios are low risk and will not be further commented.

It is noted that all the scenarios in this category involve the blackout of either Southern Norway, Southern Sweden or Southern Finland or a combination. This is mainly due to higher load concentration in these areas, and does not mean that the reliability of the power system here is lower than in other parts of the system in any way. Moreover, the critical scenarios assume operating conditions with high power exchange (import or export) to or from the area, suggesting that it is the imbalance between local generation and load that first of all causes the critical situations. With the exception of the scenario with high import to Finland, the analysis suggests that the most critical situations arise in operating conditions with very high power transfer from east to west or from north to south.

This analysis assumes that the restoration of supply following a blackout can be accomplished without very long time delays for most customers in all the scenarios. Average outage times between one and four hours are used. It is emphasized that if the outage time for some reason becomes considerably longer, this will also worsen the consequence of a blackout correspondingly.

It will be a difficult and expensive task to reduce the probability of incidents that lead to critical blackouts. Focus should be on reducing the consequences. There are different types of conditions and actions that influence on the consequences:

- Actions that prevent single failures to cause damage. These actions are related to network and station design, maintenance, protection.
- Actions and systems that enable fast detection and mitigation of developing failures. These are related to operator information systems, control systems and system protection.
- Actions and routines for efficient and fast restoration of supply following a blackout. This concerns all the power and network companies, and their preparedness to handle blackout situations (sufficient staff, plans, cooperation, communication and training).
- In the end the evaluation of risk has also to do with people's dependency of electrical power and the public's preparedness to handle critical situations.

### **A3.5 Analysis of future system**

#### **A3.5.1 Future trends and impact on risk**

This purpose of this section is to identify and analyse developments and trends that can change the risk of power system blackouts in the future.

It is generally assumed that society becomes more dependent on electricity, and that the consequences of blackouts increase as a result of this development. This is hard to quantify, and in the period towards 2010, which is the stage we use for our analysis of the future system, there will hardly be a dramatic change in the consequences of outages. Given all the other uncertainties involved, we choose not to change the classification of blackouts that was shown in Chapter 2.4.3 of the main report.

Similarly, there is no reason to believe that the probability of initiating failures and faults will change dramatically. High focus on cost reductions and possible changes in maintenance routines are factors that may increase the probability of failures. The fact that investments in the transmission grid have been low during the last decade could increase failure rates as the components in the power system grow older. In the long run, reduced maintenance will also contribute to increase failure rates. On the other hand, it is also a fact that maintenance work in itself is a factor that tends to increase the probability of failures. The total consequence of this is therefore somewhat uncertain.

Lack of staff with necessary technical competence within power system operation, planning and maintenance is also a possible threat to future risk of power system failures.

Apart from the factors above, there is uncertainty with respect to how the probability of blackouts changes as the system and the operating conditions change in the future. One reason for this can be the location of new generation resources, which has become less predictable than previously because of a lack of integrated planning of generation and transmission.

#### New generation and power flow patterns

During the last ten years there has been a trend towards more changing power flow patterns. This can be seen as a consequential effect of the common Nordic electricity market, responding to variable prices and availability of power. This has also led to increasing transmission congestions, which increase the risk of power system failures. There are reasons to believe that the power flow patterns in the future will be even more variable. The main reasons for this being:

- New generation capacity is planned in Finland with a 1600 MW new unit in Olkilouto.
- New wind farms will be built in all countries. The total capacity that will be built is to a large degree dependent on the economic conditions (markets and incentives) in the near future. Large-scale wind integration will also in some areas require transmission reinforcements.
- Uncertain plans for gas fired power plants in Norway.

#### Transmission expansion

Plans for upgrading and capacity expansion in the transmission network are naturally made in response to predicted changes in generation and consumption. Most transmission developments will contribute to increase power system security. This is clearly the case if the developments are e.g. upgrading of transformer stations to higher security levels or if new lines are built that reduce the number of hours the system experiences a bottleneck. Other developments may be purely motivated from an energy trading point of view. An example is the construction of new HVDC links to neighbouring systems. Increased exchange capacity improves the security of supply in terms of energy and stable prices. However, increasing exchange possibilities contribute to increasing transfer of power between areas, and this may have an adverse effect on the risk of power system failures.



### **A3.5.2 Risk assessment**

Based on the assumptions above, the analysis of the future system will be limited to a discussion of how the main trends affect the risk of the blackout scenarios analysed for the present system.

#### ***Scenario 1: High import to Southern Finland***

A significant amount of new generation capacity is planned to be on-line in Finland before 2010. Assuming that the new capacity contributes to decrease the number of hours with high import to Finland, this will consequently decrease the probability of this scenario.

#### ***Scenario 2: High export from Finland***

With new generation capacity there is reason to believe that the number of hours with high power export from Finland will increase in the future. This will contribute to increase the probability of this scenario. There are, however, plans for improved control and protection systems to deal with this, and therefore no major changes are expected.

#### ***Scenario 3: Helsinki area blackout***

The risk of this scenario is expected to be mainly unchanged. Increasing focus on security related to maintenance work and the lessons learned from the blackout in August 2003 may contribute to reduce probability of similar failures.

#### ***Scenario 4: Northern Sweden***

The risk of this scenario is closely related to the utilization of Interface 1. It is expected that the power transfer demand from Northern Sweden as well as from Finland will increase towards 2010, and thus Interface 1 will be a more frequent bottleneck. This will increase the risk.

#### ***Scenario 5: Southern Sweden***

A similar development is expected concerning power transfer on Interface 2. Without significant new generation capacity in the southern parts of Sweden and Norway, there will be increasing demand for power transfer on this interface. Power transfer demand is also expected to increase with new generation capacity in Finland. With the assumption that no major network expansions are realized before 2010, the risk of this scenario is increasing.

Interface 4 in the south of Sweden has also been a concern from a security point of view. It seems, however, that this problem is decreasing with new installations of reactive reserves and system protection schemes. A future uncertainty is related to whether (or to what extent) existing plans for large-scale wind power developments in the south will be realized or not.

#### ***Scenario 6: Gothenburg area***

Concrete plans exist for grid reinforcements in the vicinity of Ringhals and the Kontiskan HVDC converter stations. This will improve the operating security related to severe failures that affect both Interface 2 and the West coast interface.

Otherwise, the risk of this scenario depends on the future utilization of the West coast interface. This is primarily a problem in dry years with increasing demand for power export to Norway.

#### ***Scenario 7: Stockholm area***

As a consequence of the recent power outages in Stockholm, a project called “Stockholms Strøm” is started to reinforce and secure the main power supply to the the area. Thus, the risk of future blackouts is assumed to be decreasing.

#### ***Scenario 8: Eastern Denmark and Copenhagen***

As for the present system, the risk of future blackouts in Eastern Denmark is also closely related to the situation in Southern Sweden. The risk of critical situations is seen to increase. On the other hand, there is a potential to decrease the risk of extensive blackouts due to voltage collapse by implementation of intelligent system protection schemes.

A future uncertainty is also related to the development of wind power. If all new generation in Eastern Denmark is based on wind power, there is a concern that faults in the transmission grid can lead to extensive tripping of wind farms and thus cause critical power deficit situations. Whether this becomes a major problem depend on the wind power technology as well as system protection and control solutions to be developed in the future.

#### ***Scenario 9: Western Denmark***

Western Denmark has a considerable surplus of power generation capacity with a mix of centralized and decentralized thermal power plants and wind power. A primary challenge for the system operator is related to operation planning and balance control taking into account the variable nature of wind generation and the control limitations of the thermal power plants. The possibilities for power exchange with Norway, Sweden and Germany are thus important concerning power system security (availability of primary reserves) as well as their importance for the energy market.

Nordel’s “Systemudviklingsplan 2002” [29] has put focus on the most important transmission corridors that need capacity expansion. Two of the prioritized corridors, showing highest profitability, are the Skagerrak HVDC link between Southern Norway and Jutland and the ac interconnection between Jutland and Germany. Increased capacity on the north-south corridor through Western Denmark will certainly represent an improvement regarding the risk of energy shortage and power capacity problems. However, from the point of view of power system failures the risk will probably remain largely unchanged.

It is also noted that significant network reinforcements will be finalized before 2010. Among these are the new 400 kV line Aalborg-Århus and upgrading of the ac-connection of the Kon-tiskan 1 terminal to 400 kV voltage level. Furthermore, it is likely that a HVDC connection between Eastern and Western Denmark is realized by 2010. Eltra has put focus on developing a system design that promotes a more decentralized network structure. The aim is to make the individual sub-transmission networks more independent of the main transmission system.

All in all, it is believed that through the planned efforts the risk of extensive blackouts remain unchanged or will be reduced in the future.

#### ***Scenario 10: Southern Norway and Oslo area***

We believe that the risk of blackouts in southern Norway is slightly increasing towards 2010. The main reason is that more frequent operating conditions with either high import or high export are expected, and thus there will be more frequent bottlenecks in the transmission grid. This development assumes that new HVDC links will be realized, which will increase the power exchange capacity in Southern Norway.

#### ***Scenario 11: Western Norway***

The load demand in Western Norway is expected to increase considerably towards 2010. The power supply situation is therefore becoming more and more critical. There are several plans for network reinforcements in the area, and the future risk depends on the realization of the plans. In the worst case, if no reinforcements are performed, the risk of blackouts in this area will increase from low to medium according to our classification.

#### ***Scenario 12: Stavanger area***

The future risk in the Stavanger area is expected to be mainly unchanged. The most critical situations in this area are periods when one of the two 300 kV lines, Kjelland-Stokkeland or Tonstad-Stokkeland is out due to maintenance work.

#### ***Scenario 13: Southern Scandinavia***

In the analysis of the present system this scenario was included as an attempt to describe the most extensive blackout. In the future, this scenario may become more probable. With increased generation capacity in Finland, transmission improvements, including a second FennoSkan HVDC link, the export capacity from Finland to Sweden may exceed 3000 MW. This will enable further increase in power transfer from east to west and north to south in a situation with very low hydro-power availability in Southern Norway. The same scenario regarding series of events and separation of Southern Norway and southern Sweden will then get a somewhat higher probability.

Figure A3-7 below illustrates these discussions. The figure shows that there is generally some deterioration in the situation. However, these effects will probably be counteracted by mitigating actions of the TSOs.

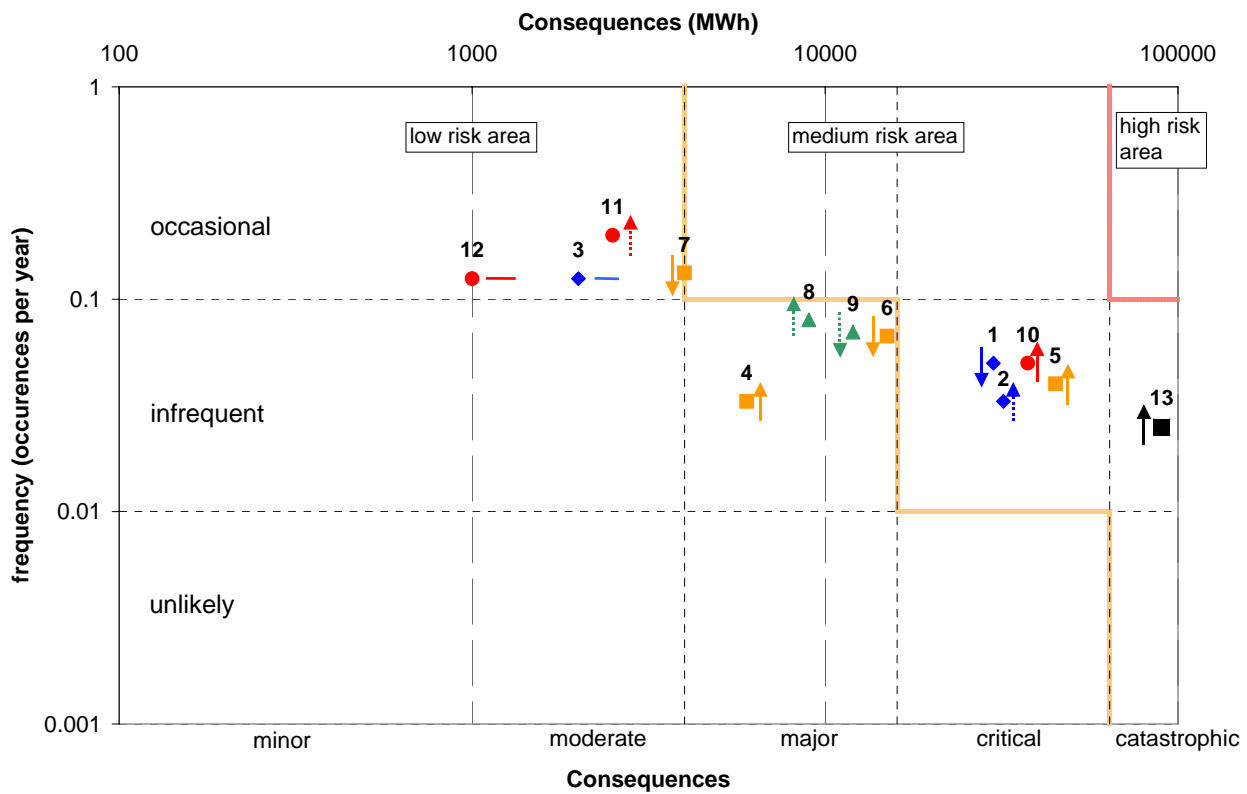


Figure A3-7: Risk analysis for the future system (2010). Expected changes between 2005 and 2010 indicated by arrows. The numbers refer to the scenarios described in Section A3.2.4. Blue coloured markers (diamonds) are used for the Finnish scenarios, or orange colours (squares) for Sweden, green (triangles) for Denmark and red (circles) for Norway.

## APPENDIX 4 DEMAND, SUPPLY AND TRANSMISSION SYSTEM DATA

The analyses of energy shortage, capacity shortage and power system failures in the subsequent chapters are based on concrete descriptions of the Nordic power system. This chapter describes the major assumptions with respect to supply, demand and the transmission system that are common for all three analyses.

### A4.1 The present Nordic power system (2005)

The description of the present system is based on the annual statistics of Nordel for 2002, which are valid for 31 December 2002. Necessary updates are made for documented changes in 2003 and expected changes in 2004, to represent the system in 2005.

#### A4.1.1 Power supply

Table A4-1 shows installed capacity in the Nordic countries (excluding Iceland) as of 31 December 2002.

Table A4-1: Installed capacity as of 31 December 2002 (Source Nordel)

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Sum</b>
Installed capacity, total <sup>1)</sup>	12 632	16 866	27 960	32 223	<b>89 681</b>
Hydropower	11	2 948	27 558	16 097 <sup>2)</sup>	<b>46 614</b>
Nuclear power	.	2 640	.	9 424	<b>12 064</b>
Other thermal power	9 733	11 235	305	6 363 <sup>7)</sup>	<b>27 636</b>
- condensing power <sup>3)</sup>		3 882	73	1 356	<b>5 311</b>
- CHP, district heating	9 019 <sup>4,5)</sup>	3 655	12	2 492	<b>15 178</b>
- CHP, industry	444 <sup>6)</sup>	2 820	185	956	<b>4 405</b>
- gas turbines, etc.	270	878	35	1 559 <sup>7)</sup>	<b>2 742</b>
Other renewable power	2 888	43	97	339	<b>3 367</b>
- wind power	2 888	43	97	339	<b>3 367</b>

<sup>1)</sup> Refers to the sum of the rated net capacities of the individual power plant units in the power system, and should not be considered to represent the total capacity available at any single time.

<sup>2)</sup> Includes the Norwegian share of Linnvasselv (25 MW).

<sup>3)</sup> Includes capacity conserved for an extended period, Finland (230 MW)

<sup>4)</sup> Includes condensing power.

<sup>5)</sup> Includes long-time reserve of Vendsysselværket (295 MW).

<sup>6)</sup> Included industrial generated producer (appr. 24 MW).

<sup>7)</sup> Includes capacity of power plants which are included in the agreement considering the power reserve in Sweden

Until 31 December 2005, the following changes in the supply system have been made and are expected, respectively:

### Denmark

Increase in wind power of 1 TWh, representing 500 MW with an expected load factor of 2000 hours

### Finland

No change.

### Norway

Increase of 28 MW hydropower and 53 MW wind power.

### Sweden

Increase in wind power of 1 TWh, representing 385 MW with an expected load factor of 2600 hours. Installed capacity of condensing power includes approximately 1000 MW presently contracted by SvK that may become unavailable without some kind of support.

The resulting assumed capacities ultimo 2004 are shown in the next table.

Table A4-2: Assumed installed capacity as of 31 December 2004

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Sum</b>
Installed capacity, total	13 082	16 866	28 041	32 608	<b>90 597</b>
Hydropower	11	2 948	27 586	16 097	<b>46 642</b>
Nuclear power	.	2 640	.	9 424	<b>12 064</b>
Other thermal power	9 733	11 235	305	6 363	<b>27 636</b>
- condensing power		3 882	73	1 356	<b>5 311</b>
- CHP, district heating	9 019	3 655	12	2 492	<b>15 178</b>
- CHP, industry	444	2 820	185	956	<b>4 405</b>
- gas turbines, etc.	270	878	35	1 559	<b>2 742</b>
Other renewable power	3 338	43	150	724	<b>4 255</b>
- wind power	3 338	43	150	724	<b>4 255</b>

When evaluating the capacity balance, it is of great importance to estimate the share of installed capacity that is unavailable during peak demand<sup>23</sup>. There are three grounds for reduced availability:

1. Reduced availability of generation due to maintenance, forced outage or reduced resource availability (the latter is primarily a hydro issue, but can occur in thermal systems when fuel is short for any reason).
2. Available capacity lies behind transmission bottlenecks.

<sup>23</sup> In principle at all times. The capacity balance can be tight, even in periods with moderate demand. An illustration of this fact is Statnett's purchase of capacity reserves in week 12 and 13 in 2004, when demand is moderate and reserves normally should be ample. Availability can be reduced at other times because of limited water availability in the hydro system or maintenance of generation and/or transmission. In countries with a flatter load profile than the Nordic system, "peak demand" problems can occur all year. In this study we focus on peak demand during cold winter days only, as this is generally seen as the most critical situation in the Nordic system.

### 3. Reserve requirements.

With regard to reduced availability of generation capacity and transmission bottlenecks, we have used Nordel data as far as possible [29], [50], [51], together with some judgement where explicit numbers are not available or inconsistent. The resulting availability data are summed up in the following table:

Table A4-3: Estimated availability of generation

	Hydro	Nuclear	CHP / Thermal	Wind
Denmark	0.86	-	0.82	0.02
Finland	0.86	1.00	0.82	0.10
Norway	0.88	-	0.90	0.10
Sweden	0.86	1.00	0.82	0.10

Specifically for hydro, which lies far from demand centers, estimated unavailability includes the effect of transmission congestion, besides the hydrological and hydraulic effects and the effect of maintenance and failures. Nuclear availability is normally assumed 100 %. This is discussed more in the analysis of capacity shortage in Chapter Appendix 2. The availability of thermal and CHP plants is reduced because of maintenance, failures and heat demand. It may also include some market uncertainty related to the fact that capacity is mothballed in the case of low prices. The availability of wind power in Denmark with 90 % certainty is only 2 % (Eltra). Availability for the other countries is assumed higher due to their greater geographical spread.

With respect to reserves, we assume that all primary and secondary reserves have to be available from the generation system (a discussion and further evaluation of this issue is given in Chapter Appendix 2). The following reserves are required or recommended by Nordel:

Table A4-4: Nordel reserve requirements and recommendations

	Primary Reserves		Secondary Reserves
	Frequency Control	Disturbance	Fast Reserve
Eastern Denmark	25	90	600
Western Denmark	35	75	400
Finland	135	205	1000
Norway	200	313	1200
Sweden	240	303	1200
Nordel	600	1000	4400

Note that a considerable share of the Frequency Control Reserves in Finland are provided from Russia, while a similar share of the Disturbance Reserves in Eastern Denmark are provided over the Kontek interconnection.

#### **A4.1.2 Power demand**

Demand depends on prices, and as such it is difficult to make forecasts of future demand. E.g. a shortage of supply with respect to a forecast, at least under normal hydro conditions, will not result in physical shortage, but in high prices and reduced demand. Being aware of this, it is still necessary to establish basic demand scenarios to be able to do any kind of quantitative analysis of the vulnerability of the power system. The effect of prices is assessed in the respective analyses. Expected consumption of electrical energy is given as one number. With respect to peak demand, three scenarios are used:

- Normal winter, with an expected recurrence of 2 years
- Cold winter, with an expected recurrence of 10 years
- Extreme winter, with an expected recurrence of 30 years

#### **Denmark**

Consumption for West Denmark is based on Eltra forecast, 21.6 TWh [55]. For East Denmark a forecast from Elkraft System that was available on a spreadsheet that was available on their web site was used, showing 14.6 TWh in 2005 (a newer forecast later showed 14.5 TWh).

Expected peak demand in a normal winter in West Denmark is 3850 MW [55]. According to the same source, demand will be 5 % higher in a cold winter, resulting in 4040 MW. For East Denmark, the latest forecast on Elkraft System's web site is used, showing 2860 MW for a cold winter in 2005. Demand for a normal winter is estimated by using the same ratio between a normal and a cold winter as used by Nordel for 2007 [29], resulting in 4040 MW in West Denmark and 2860 MW in East Denmark.

Given the relatively low temperature dependency of demand in Denmark, peak demand in an extreme winter is assumed equal to peak demand in a cold winter.

#### **Finland**

The latest forecast by the Finish Energy Industry's Federation Finergy shows an expected consumption of 88.1 TWh in 2005 (interpolated between 2002 and 2010). The same forecast gives an expected peak demand in a cold winter of 15000 MW. Peak demand in a normal winter is estimated by using the same ratio between a normal and a cold winter as used by Nordel for 2007 [29], resulting in 14660 MW. Given the relatively low temperature dependency of Finnish demand, peak demand in an extreme winter is expected to be equal to a normal winter.

#### **Norway**

Forecasts for 2010 is based on [53], which uses three scenarios with demand varying from 123.3 to 138.8 TWh. The lowest scenario is an "Environment" scenario. If this scenario is realized and corresponding reductions in demand occur in the other Nordic countries, vulnerability with respect to energy and capacity shortage will be affected. However, the balance between supply and demand is not necessarily better in such a scenario, because also supply will be limited.

In this study, Statnett's base scenario is used. This has a total demand of 134.1 TWh in 2010, of which 4.2 TWh is related to increase in demand by the oil and gas industry. However, we assume a reduction of 1 TWh due to an expected new building code [54], resulting in total demand of 133.1 TWh in 2010.



Corrected for deviations from normal temperatures, demand in recent years has been (NVE):

2000: 128.5 TWh  
2001: 126.2 TWh  
2002: 123.7 TWh  
2003: 117.6 TWh

In this development, the unusually low prices in 2000 and the unusually high prices in 2003 have to be taken into account (simulations with the EMPS model will also take this into account to some extent). Based on these numbers and the expected demand in 2010, a total consumption of 125 TWh in 2005 is assumed.

Expected peak demand in normal and cold winters is found by interpolating between the numbers given for 2004 and 2007 in [29], resulting in 22200 MW and 23350 MW respectively. To estimate extreme demand, a memo by Statnett from 1996 was used that concluded that extreme demand could be about 400 MW higher than peak demand in a 10-year winter.

### **Sweden**

According to Svensk Energi, total consumption in recent years has been:

2000: 146.6 TWh  
2001: 150.5 TWh  
2002: 148.7 TWh  
2003: 145.3 TWh

These numbers are not corrected for deviations from normal temperature. According to the Energy Authority (Energimyndigheten) the forecast for 2004 is 152 TWh. A new forecast will be available in the course of 2004. Given the low consumption in 2003 an demand of 151 TWh in 2005 is assumed.

Peak demand for a normal winter is estimated by interpolating the numbers given in [29] for 2004 and 2007, resulting in 27000 MW. To find peak demand in a cold winter, the same ratio between a normal and a cold winter is used as in 2004, giving 29000 MW. [29] uses 28800 both in 2004 and 2007, but it looks a little strange that peak demand should not increase when energy consumption increases. According to personal communication with Svenska Kraftnät, extreme demand could be 1500 MW higher than estimated peak demand in a cold winter.

The following table sums up the discussions above:

Table A4-5: Demand forecasts for 2005

	Consumption (TWh)	Peak Demand (MW)		
		Normal winter	Cold winter	Extreme winter
Denmark	36.2	6650	6900	6900
Finland	88.1	14660	15000	15000
Norway	125.0	22200	23350	23750
Sweden	151.0	27000	29000	30500

### A4.1.3 Transmission

Transmission capacities between areas are based on Nordel data [28]. No significant changes in the transmission system are expected by 2005. There are on-going projects in all the Nordic countries for upgrading and expansion of the 400 kV transmission grid, but most of these projects focus on internal bottlenecks. Thus, the transmission capacities that are used or assumed in the analysis of the present system (2005) are identical to the normal transfer limits and exchange capacities of the present grid.

In the EMPS calculations for the energy shortage analysis, slightly reduced capacities are used to take into account to some extent that for many reasons, full physical capacity will not always be utilized by the market. These capacities are given in Table A4-6 and Table A4-7 below.

Table A4-6: Interchange limits between the Nordic countries (values in MW)

From: To:	Norway	Sweden	Finland	Denmark- east	Denmark-west
Norway	X	3150	120	X	900
Sweden	3150	X	2200	720	1775
Finland	100	1600	X	X	X
Denmark-east	X	1700	X	X	300
Denmark-west	900	720	X	300	X

Table A4-7: Import possibilities to the Nordic area (values in MW)

From: To:	Sweden	Denmark- east	Denmark- west
Poland	400	X	X
Germany	400	800	600

Finland is in addition modeled with a 10.5 TWh import from Russia.

## A4.2 The future Nordic power system (2010)

For a future system we use an expected system and market description for 2010. Assumptions are to a large degree based on Statnett [52], but additional updated information has been used where available.

### A4.2.1 Power supply

#### Denmark

Increase in 1.4 TWh in wind power, corresponding to 700 MW with a load factor of 2000 hours.

#### Finland

One nuclear plant of 1600 MW generating 12.5 TWh annually is expected to be commissioned in 2009.

#### Sweden

- Barsebäck 2 (600 MW) is expected to be decommissioned between 2005 and 2010.
- An increase in wind power of 1 TWh or 385 MW with a load factor of 2600 hours.
- Gas fired CHP plant in Göteborg, 300 MW, 1.5 TWh.

#### Norway

- Øvre Otta, 171 MW, 525 GWh
- Sauda, 100 MW, 500 GWh
- Increase in capacity in existing plants, 500 MW, no energy effect
- Gas plants, 800 MW, 6 TWh
- Total wind power 3 TWh or 1000 MW with a load factor of 3000 hours.

The resulting assumed capacities in 2010 are shown in the next table.

Table A4-8: Assumed installed capacity in 2010

	<b>Denmark</b>	<b>Finland</b>	<b>Norway</b>	<b>Sweden</b>	<b>Sum</b>
Installed capacity, total	13 772	18 466	30 462	32 693	<b>95 393</b>
Hydropower	11	2 948	28 357	16 097	<b>47 413</b>
Nuclear power		4 240		8 824	<b>13 064</b>
Other thermal power	9 733	11 235	1 105	6 663	<b>28 736</b>
- condensing power		3 882	873	1 356	<b>6 111</b>
- CHP, district heating	9 019	3 655	12	2 792	<b>15 478</b>
- CHP, industry	444	2 820	185	956	<b>4 405</b>
- gas turbines, etc.	270	878	35	1 559	<b>2 742</b>
Other renewable power	4 028	43	1 000	1 109	<b>6 180</b>
- wind power	4 028	43	1000	1109	<b>6 180</b>

### A4.2.2 Power demand

#### Denmark

For West Denmark, the Eltra forecast [55] is used, showing an expected consumption of 23.0 TWh and a normal peak demand of 4115 MW. Peak demand in a cold or extreme winter is estimated as 4320 MW under same assumption as in A4.1.2. For East Denmark, the newest forecast of Elkraft System [56] shows an expected consumption of 15.8 TWh and a corresponding peak demand in a cold winter of 3110 MW. Normal peak demand is estimated to 3040 MW.

#### Finland

The Finergy forecast for 2010 has an expected consumption of 96.4 TWh<sup>24</sup> and a peak demand in a cold winter of 16300 MW. Normal peak demand is estimated to 15930 MW.

#### Norway

Expected consumption in 2010 is 133.1 TWh cf. A4.1.2. According to Statnett, peak demand in a cold winter is estimated to 24800 MW [53]. Peak demand in a normal winter is estimated by using the same ratio between a normal and a cold winter as Nordel uses in [29] in 2007. Extreme demand is assumed to be 400 MW higher than demand in a cold winter.

#### Sweden

No energy forecast for Sweden was available for this study. We have estimated demand in 2010 by assuming an annual increase of 1 TWh between 2005 and 2010, corresponding to an average annual growth of 0.7 % and a total demand of 156 TWh. Peak demand in 2010 is estimated by assuming the same load factor in 2010 as in 2005 (5590 hours). This results in 27900 MW in a normal winter and 30000 MW in a cold winter. Extreme demand is assumed to be 1500 MW higher than peak demand in a cold winter.

The following table shows the complete forecast for 2010:

Table A4-9: Demand forecasts for 2010

	Consumption (TWh)	Peak Demand (MW)		
		Normal winter	Cold winter	Extreme winter
Denmark	38.6	7155	7430	7430
Finland	96.4	15930	16300	16300
Norway	133.1	23530	24800	25200
Sweden	156.0	27900	30000	31500

<sup>24</sup> The latest forecast from the Finnish Ministry of Trade and Industry has a consumption of 94.2 TWh in 2010 in its WM ("With Measures") scenario, slightly lower than the Finergy forecast. This forecast became available too late in the project to be taken into account.

### **A4.2.3 Transmission**

There is ongoing work within Nordel that focuses on coordination and prioritization of projects to increase transfer capacities on the most important transmission corridors and borders with the Nordic grid. This work [57] has put highest priority on the north-south corridors (Norway-Denmark-Germany) and east-west (Finland-Sweden-Norway) corridors. Among the most interesting projects from an economic point of view seem to be:

- Skagerrak 4 (Expansion of HVDC link between Southern Norway and Western Denmark)
- Kattegat, alt. 1 (HVDC link between South-eastern Norway and Eastern Denmark)
- Kattegat, alt. 2 (HVDC link between South-eastern Norway and Southern Sweden)
- Kontiskan (Expansion of HVDC link between Southern Sweden and Western Denmark)
- Hasle interface (Expansion of ac connection)
- Nea-Järpströmmen (Expansion of ac connection between Mid-Norway and Sweden)
- West coast interface (Expansion of ac connection).
- Fennoskan 2 (Expansion of HVDC link between Sweden and Finland)

There is also likely that some new transmission projects will be realized not only because of their pure economic value, but also from operational security motivations.

In this study we have assumed that by 2010 none of these major projects are realized.

In the energy shortage analysis the interchange capacities between the countries are the same as in Table A4-6 and Table A4-7, except for the capacity between Norway and Sweden, which is increased with 650 MW in both directions (350 MW increased capacity on “Hasle-snittet” and 300 MW increased capacity between Norway and Jämtland).



## APPENDIX 5 THE EMPS MODEL

### A5.1 The EMPS model overview

The EMPS-model consists of two parts.

- A strategy evaluation part computes regional decision tables in the form of expected incremental water costs for each of a defined number of aggregate regional subsystems. These calculations are based on use of a stochastic dynamic programming-related algorithm for each subsystem, with an overlaying hierarchical logic applied to treat the multi reservoir aspects of the problem.
- A simulation part evaluates optimal operational decision for a sequence of hydrological years. Weekly hydro and thermal-based generation is in principle determined via a market clearance process based on the incremental water value tables calculated for each aggregate regional subsystem. Each region's aggregate hydro production for each time step is distributed among available plants using a rule-based reservoir drawdown model containing a detailed description of each region's hydro system.

Time resolution in the model is 1 week, or optionally fractions of a week (e.g. 'peak load', 'off-peak day', 'night', 'weekends').

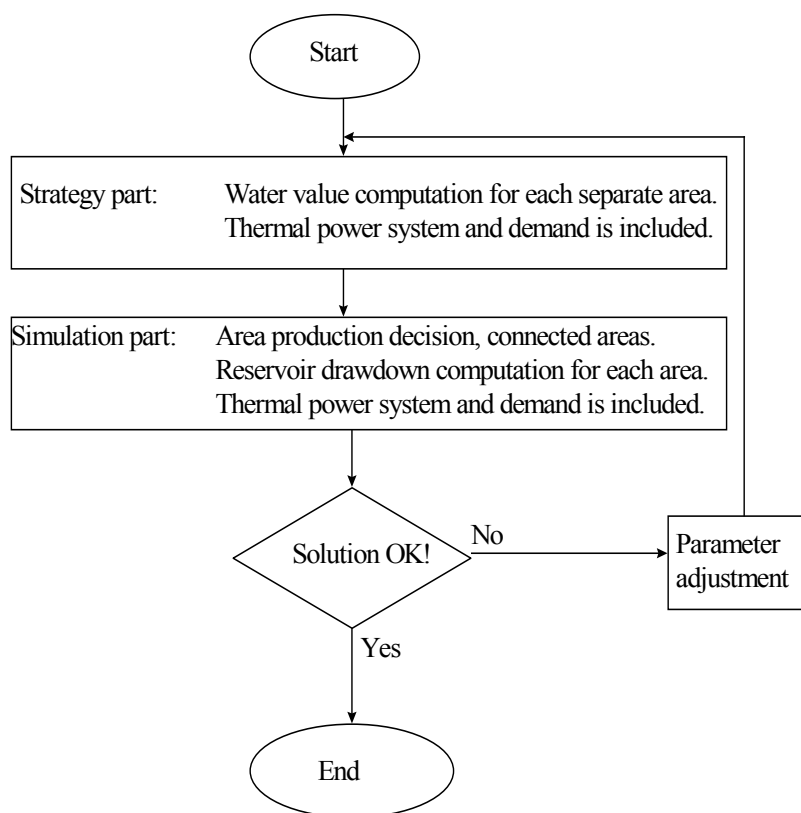


Figure A5-1: Overall simulation process logic

When we have got convergence after the calculation the user must decide if the solution in Figure A5-1 is OK and maybe redo the calculation with some adjusted parameters. Figures that should be checked are e.g. the status of hydro reservoir curves and unreasonable spillage from reservoirs.

## A5.2 The system Model

In the EMPS-model the modelled interconnected power system is divided into regional subsystems, as shown in the sample system in Figure A5-2. System subdivision may be based on hydrological or other characteristics having to do with the local hydro systems, or it may be based on bottlenecks in the transmission systems.

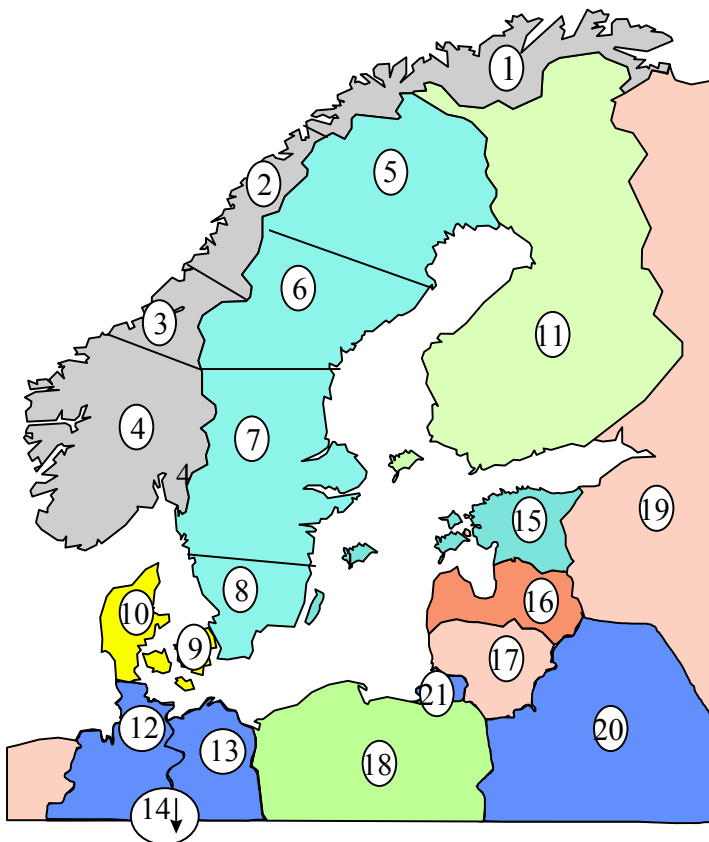


Figure A5-2: Regional subsystems in a model of the Baltic Ring power system.

Within each subsystem hydropower, thermal power and consumption (firm power or spot power demand) may be modelled, as illustrated in Figure A5-3. In addition the transmission system between subsystems is modelled with defined capacities and linear losses. Certain transmission fees may be modelled.



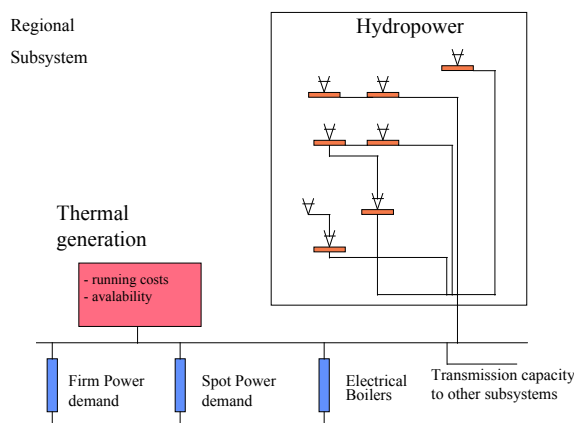


Figure A5-3: Subsystem description

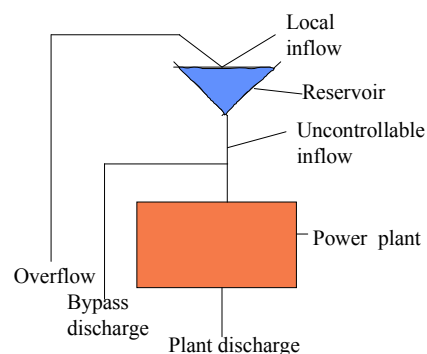


Figure A5-4: Standard plant/reservoir module

The **hydropower** system within each region/subsystem may be modelled in detail. Based on standard plant/reservoir modules as shown in Figure A5-3. Even large complicated river systems may be modelled. A model of the Norwegian / Swedish hydro system may for example involve from 200 to 800 plant/reservoir modules, depending on the degree of detail. Figure A5-4 shows an example of a small regional hydro system modelled using standard modules. The following properties may be attached to each plant/reservoir module:

- a reservoir, defined by its volume and relationship between water volume and elevation above the sea (Can be 0 if it is a run-of river hydropower station).
- a plant, defined by its discharge capacity and a piecewise linear relationship between discharge and generation.
- inflow (weekly) either to the reservoir or directly to the plant.
- different routes for hydraulic connections, plant discharge, bypass discharge and reservoir overflow.
- variable constraints on reservoir contents and waterflow (plant or bypass discharge).
- pumping capability, either reversible turbines or dedicated pumping turbines.

Inflow statistics normally consists of normally 40 years of observed weekly run-off at different geographic locations. Average annual inflow to a reservoir or power station may be referred to selected years, e.g. 1931-1960 or 1950-1990. The time series is a measurement of natural flow variation in rivers and ought to be measured in close vicinity to the catchment area where it is applied.

**Thermal generation** units including CHP units are usually defined by their variable costs (defined by fuel costs etc.), capacity, average weekly availability and are modelled as such. Both costs and capacities are modelled as function of time (maintenance work cycles may be included). This type of modelling assumes that fuel can be purchased and used as needed. This is the case with coal- and oil-fired plants, nuclear plants and some gas fired plants.

Typical of some fossil-fuelled plants are, however, that they are contractually or otherwise bound to receiving a specified ‘inflow’ of fuel or produce a certain amount of power as e.g. for some CHP plants, which are bound by a heat delivery. This is particularly the case with gas-fired plants. The fuel inflow may be specified continually, or for example annual or pluri-annual volumes may be specified. Thermal units bound by this type of constraints on fuel inflow are either modelled by fixed energy series injected directly into the power system (specified volume per week or fraction of a week, no local fuel storage) or by equivalent hydro plants. The latter may be used both in the case where local fuel storage is possible, and in the case where fuel volumes are specified only for longer periods of time, for example annually.

Two types of **power consumption** are modelled: firm power demand and spot power demand, where consumption per time step is a function of spot market price:

*Firm power demand* is modelled as specified power consumption week by week (or/and for fractions of week) as illustrated in Figure A5-5. Inability to deliver firm power entails buying curtailment power at high costs.

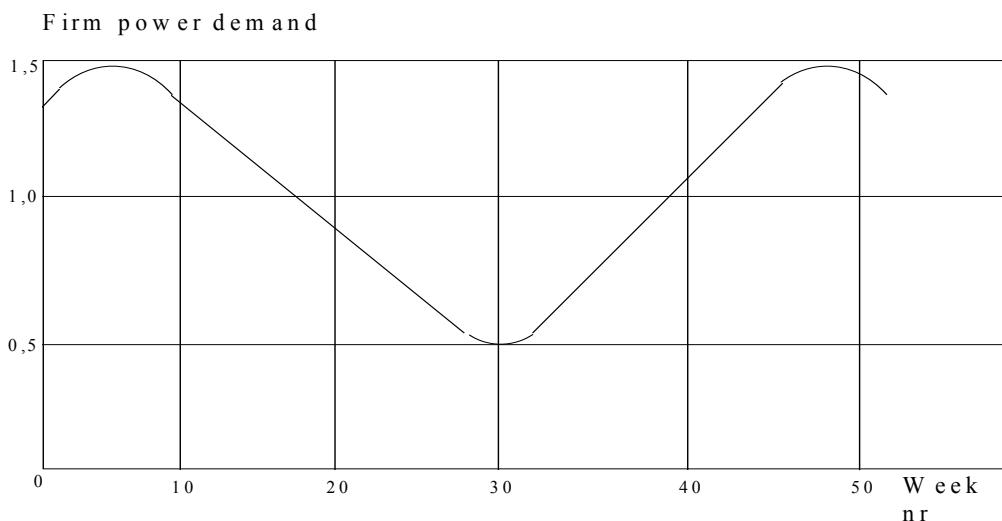


Figure A5-5: Typical annual profile for firm power demand from Norwegian households

*Spot power demand* within each subsystem is modelled as a stepwise price-quantity relationship for each week (or/and a fraction of a week). This market consists mainly of electric boilers and some industrial consumption. Figure A5-6 illustrates a model of this market for a specific week. As the figure shows, thermal generation capacity (assuming fuel can be purchased and used as needed) and rationing are modelled principally in the same way as spot power demand.

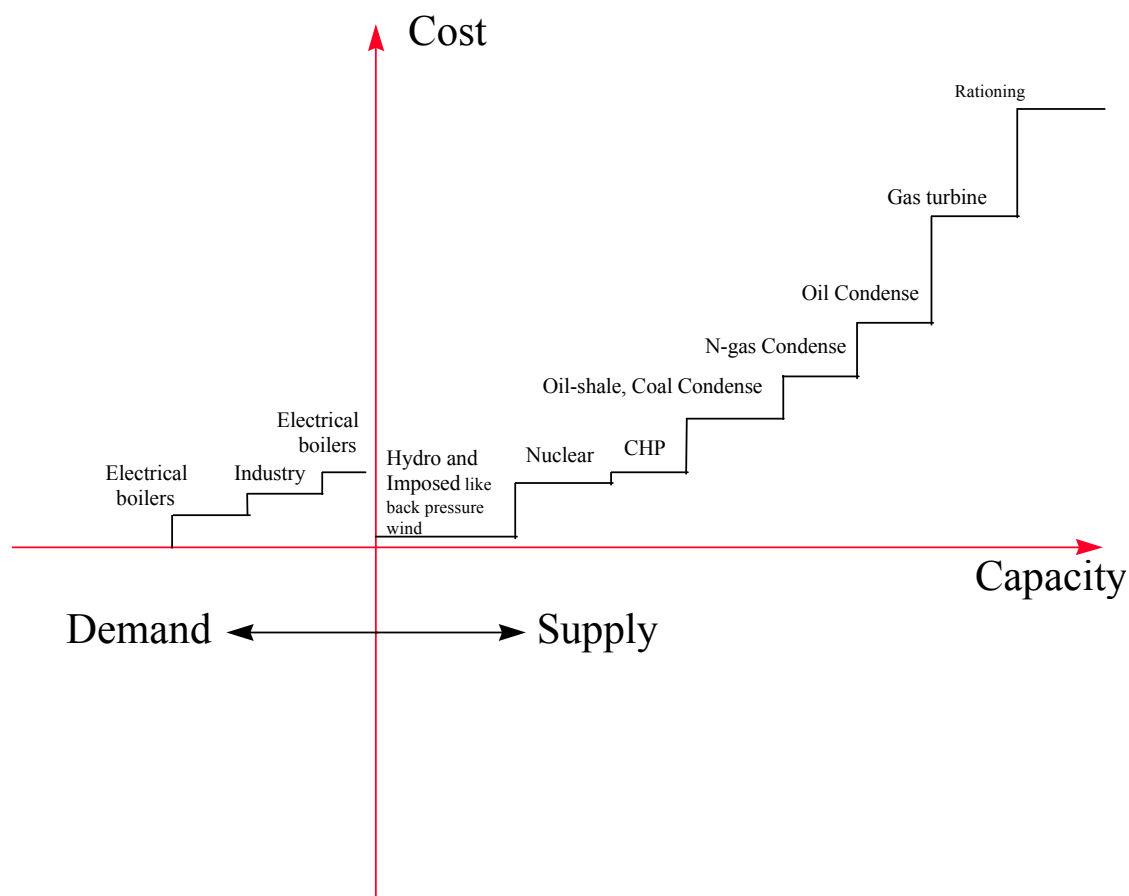


Figure A5-6: Sample spot power market, thermal system and curtailment costs for a specific week

**Power exchange** between countries, or between any interconnected subsystem for that matter, may be spot exchange or contractually fixed exchange.

Optimal **spot exchange** between subsystems is one of the results of the market clearance process in the EMPS-model, given by incremental power costs, limited transmission capacity, transmission losses and any transmission fees which might be incurred. ‘Transmission fees’ in the model may not only be fees for transmission of power, but also reflect the profit required by a country or subsystem before being willing to exchange power with another subsystem which may have a different framework.

**Contractually fixed exchange** between subsystems is modelled as a firm power obligation for the exporting subsystem and as a fixed energy inflow injected into the importing subsystem. Transmission capacities for spot exchange would have to be modified to take into account the transmission of firm power.

One interesting case of firm power exchange is the aspect of using a hydro system as a supplier of peak power to a thermal. At peak load periods each week firm power would be exported from the hy-

dro to the thermal system. At off-peak hours the same energy could be returned as firm power, or exchange at off-peak hours could be based on spot exchange. Studies have been conducted using the EMPS-model to study the probability of such arrangement.

### A5.3 Strategy part of the EMPS-model

To limit the computation burden, the strategy part of the EMPS-model is forced to utilize an aggregate model representation of the hydro system within each regional subsystem, i.e. an aggregate energy reservoir with an equivalent power plant and energy time series for controllable and none controllable inflow. Otherwise the subsystem models are as indicated earlier.

Given the stated multireservoir model description, the objective of the long-term optimization process is to establish an operation strategy that for each stage in time (time resolution in the model is 1 week, or optionally fractions of a week [e.g. 'peak load', 'off-peak day', 'night', 'weekends']), produces the 'best' decision vector, given the system state at the beginning the beginning of the stage. By 'best' decision is understood the sequence of turbine and spilled water volumes that contribute to minimising the expected operational costs during the period of analysis. By system states is understood regional reservoir storage from optimal control can in principle be solved by the recursive equation.

$$\alpha_t(X_t) = E \{ \text{Min}(C_t(U_t) + \alpha_{t+1}^*(X_{t+1})) \} \quad (1)$$

$$A_t | X_t U_t$$

subject to the constraints that water balance equations and bounds on states and decision variables must be fulfilled at each stage. The interpretation of terms in (1) is as follows

- $t$  : index of stage
- $X_t$  : state vector at the beginning of stage  $t$
- $\alpha_t(X_t)$ : expected value of the operation cost from stage  $t$  to the end of the planning period under the optimal operation policy
- $A_t | X_t$  : the distribution of inflow volumes  $A_t$  conditioned by state  $X_t$
- $E\{ \}$  : represents 'expected value'
- $U_t$  : decision vector for stage  $t$
- $C_t(U_t)$ : immediate cost associated with decision  $U_t$

The solution of (1) requires the definition of discretized states. The number of such states increases exponentially with the number of state variables in the problem. Thus formal SDP-solution becomes unfeasible when the number of reservoirs exceed 2-3.

For practical solution of the multireservoir decision problem an approximate methodology has been developed. A stochastic DF-related algorithm is used as the 'nucleus' for solving each regional sub-problem and an overlaying hierarchical logic is applied iterative to treat the multireservoir aspect. The process is illustrated in Figure A5-7.

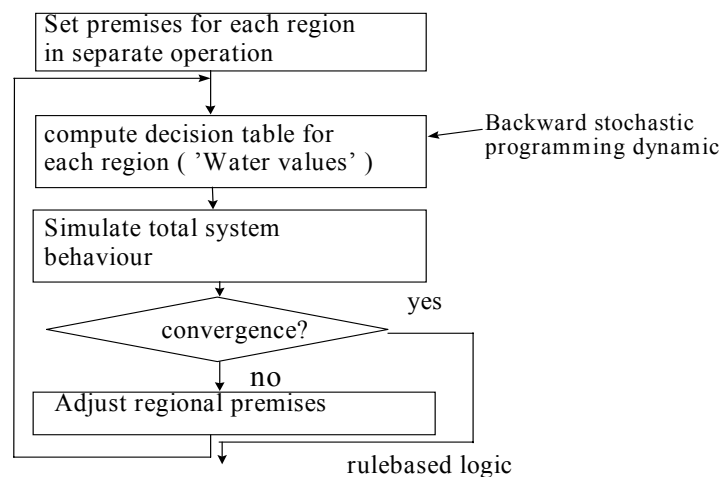


Figure A5-7: Main logic to handle multireservoir problem

A regional decision table in terms of incremental water cost is first calculated for each subsystem decoupled from the others. A version of backwards SDP called the ‘water value method’ is used to this end.

Simulation of total system behaviour is next performed using the computed decision tables to determine energy production in each subsystem, energy exchange between subsystem and transactions with neighbouring countries.

Feedback is then executed conditionally: If a stable and satisfactory solution is found, the process is finished. If not, the result from the simulation is used to adjust regional premises and return then made to regional decision table computation.

A convergence criterion is that the error in the power flow between areas is minimized.

After we have convergence it could be needed to adjust regional premises and rerun the calculations depending on the shape of the hydro reservoir curves.

#### A5.4 Simulation part of the EMPS-model

In the simulation part of the EMPS-model system performance is simulated for a chosen sequence of hydrological years. Based on the incremental cost tables calculated previously for each aggregate regional hydro system, weekly operational decisions on power generation (hydro, thermal) and consumption (spot consumption, curtailment of firm power consumption) are made in what can be termed a market clearance process. A detailed rule-based reservoir drawdown model affords the distribution of each subsystem’s aggregate hydro production among available plants for each time step. Historical inflow series covering a period of typically 40 years are basis for simulation. Figure 8 illustrates the weekly operational decision process summarized in the following points.

- Based on current reservoir levels and incremental cost tables for stored hydro energy, optimal generation, spot consumption and exchange are calculated on an aggregate subsystem level for all periods within the week (e.g. peak load, off-peak day, night, weekend). This is afforded by a network flow algorithm

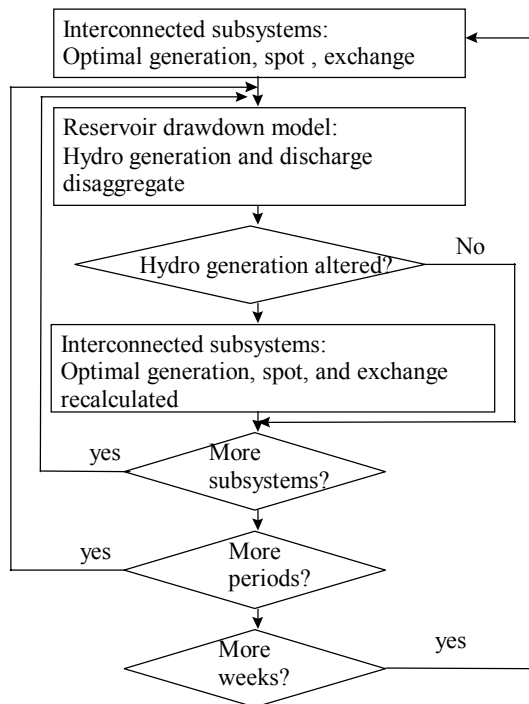


Figure A5-8: The weekly decision process in the EMPS-model's simulation part

For each period within a week, the following is repeated for each subsystem with a local hydro system:

- A rule-based reservoir drawdown model seeks to distribute the desired hydro production among available plants. Constraints in the hydro system may cause the reservoir drawdown model to deviate from the generation found to be optimal at aggregate subsystem level. In a case where increasing hydro generation will cause loss of water (e.g. bypass past plants placed in cascade) the cost of increasing local hydro production is weighed against the cost of deviation from desired production. The cost of deviation is calculated on the basis of a stepwise cost-quantity function showing power supply and demand as a function of price from neighbouring subsystems as well as local thermal capacity and spot power demand. This function has to be constructed specified for each subsystem and for each step in time, as it is a function of reservoir state in all other subsystems.
- If resulting hydro production deviates from 'desired' subsystem production, then optimal generation, spot consumption and exchange are recalculated at the subsystem level using the network flow algorithm. This time, however hydro generation is fixed for those subsystems that have already been scheduled by the reservoir drawdown model.

At the end of each week, the aggregate reservoir level is updated with results from the reservoir drawdown model and hence premises are set for next week's operational decisions.

As stated earlier, the disaggregation of regional subsystem storage into individual reservoir storage and subsystem hydro production into individual plant production is afforded by a detailed reservoir drawdown model, which utilizes a rule-based logic for reservoir depletion. The model operates with 2 types of reservoirs:

- Buffer reservoirs, whose operation is defined by guide curves. These are mainly reservoirs with low storage capacity in relation to inflow (e.g. run-of-river type).
- Regulation reservoirs, which are operated according to a general reservoir drawdown strategy (rule-based).

The basic goal of the reservoir drawdown strategy is to produce a specified amount of energy in such a way as to minimize expected future operational costs. This goal is sought fulfilled by:

- seeking to minimize risk of overflow during that part of the year when inflow is greater than discharge.
- seeking to avoid loss of generation capacity caused by empty reservoirs during that part of the year when discharge is greater than inflow.

In the Nordic countries this implies dividing the year into a ‘filling’ season (late spring, summer and early fall with high inflow, low power consumption) and a ‘depletion’ season (late fall, winter and early spring with low inflow and high power consumption).

**Environmental** impact from thermal power plants is modelled as follows:

After each calculation with the EMPS-model accumulated power production from all power plants is calculated for the considered period of time (normally one year).

The power production is multiplied by a set of emission coefficients ( $\text{SO}_2$ ,  $\text{NO}_x$ ,  $\text{CO}_2$  and dust) resulting in emission levels both country-wise and for the total system.

The emission coefficients are determined on the bases of technical data for the power plants (efficiency, fuel type, de-sulphurization etc.).

### A5.5 Results from the calculations

**Results** from the EMPS-model's simulation part include:

- Marginal costs, interpreted as spot prices
- Hydro systems operation (reservoirs, generation, water inflows).
- Thermal generation.
- Power consumption, curtailment.
- Exchange between subsystems.
- Economic results
- Emission figures (SO<sub>2</sub>, NO<sub>x</sub>, CO<sub>2</sub> and dust)
- Incremental benefits figures of increasing capacity in transmission and generation facilities.

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