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Exchange of balancing resources between the Nordic synchronous system and the Netherlands / Germany / Poland

Ove S. Grande
Gerard Doorman
Bjørn H. Bakken

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SINTEF Energy Research

Address: NO-7465 Trondheim, NORWAY
Reception: Sem Sælands vei 11
Telephone: +47 73 59 72 00
Telefax: +47 73 59 72 50

www.energy.sintef.no

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CONTRIBUTOR(S)

OSG. Ove S. Grande, Gerard Doorman (NTNU), Bjørn H. Bakken

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RESULT (summary)

The development and growing integration of power markets and the rapid expansion of new renewable energy sources (RES) with less predictable output, will increase the need for balancing services in the near future. This is the background for the Competence Building (KMB) project "Balance Management". This initial study provides an overview of the main principles for balance management and the challenges and possibilities related to exchange of reserves between countries and between separate synchronous systems via HVDC-links.

The report starts with an introduction to the present practice with regard to balance management in the Nordic and the Northern part of the European Continent. The ongoing process towards Market Coupling between the different day ahead markets in Central Western Europe (CWE) and the Nord Pool area is described as a fundamental background for future integration of the balancing services. So is the Intraday trading, which also will be implemented in all the involved countries in a course of a few years.

The use of terminology varies from region to region, reflecting the different properties and history inherited in the different parts of the power system. The main terms regarding imbalances, reserves, control actions and control regions/areas are therefore defined in the report in order to provide a common understanding.

Market based solutions for prioritisation of the resources in merit order is used for secondary control in the Nordic system and in the Netherlands, Germany and Poland. The main difference is the technical part where the secondary control on the Continent is based on Automatic Generation Control (AGC) while "manual" control of the "regulation objects" is used in the Nordic countries. Descriptions of the technical aspects, including control of HVDC connections, are presented in Appendix B and C in the report.

The present schemes for power exchange between the two separate synchronous systems via HVDC links are described and potential models for exchange of balancing resources are finally discussed as input to further studies. The project will in the following focus on both technical aspects, regarding control of regulation objects and HVDC links, and market issues:

- Exchange of manually activated reserves.
- Control schemes based on Automatic Generation Control (AGC) across HVDC links.
- Integrated balancing markets with focus on the connection and interplay between the day ahead, intraday and balancing markets, and the impacts on the real available balancing resources in the hour of operation.

KEYWORDS

SELECTED BY AUTHOR(S)		
	Balance Management	Reserves
	TSO	HVDC links

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1 INTRODUCTION

This report documents one of two initial studies in the Competence Building project "Balance Management" as a preparation to subsequent activities. The report provides an overview of the main principles for balance management, and the challenges and opportunities related to exchange of reserves between countries and between separate synchronous systems via HVDC-links. Potential models for exchange are finally discussed as input to further studies.

The content is based on previous SINTEF studies, specific reports and descriptions of rules, discussions with stakeholders, practises and issues of harmonization available on the websites of the most relevant actors.

1.1 BACKGROUND AND SCOPE

With the development and growing integration of power markets, specific attention is given to the exchange of balancing services between balancing areas in different countries. Moreover, it must be expected that the need for balancing services will increase due to rapid expansion of new renewable energy sources (RES) with less predictable output. By having a system-wide approach instead of a balancing area approach, reserve costs can be reduced. Cost savings are obtained partly because plants can be operated at better efficiency and partly because cheaper plants can be activated in real time.

The continuous and rapid expansion of wind power generation with growing share of large scale off-shore projects is one of the main challenges with regard to future balance management in Northern Europe. According to UCTE [1] more that 70 % of the wind power installed worldwide is integrated in the synchronous interconnected network in continental Europe. So far the integration of wind power has been managed without serious problems due to extra operational and technical measures taken by the Transmission System Operators (TSOs).

This new production capacity along with other types of RES has a limited predictability and has an intermittent generation profile. Additional balancing and reserve power in production and consumption, start-up and shut-down ability of base load units, as well as market arrangements, are needed.

This study is primarily focused on the present balancing mechanisms and principles for bidding, prioritisation and remuneration of the balancing resource that are used for three main purposes:

- Maintaining frequency and time deviation within the defined limits
- Keeping the balance of the region/area within limits
- Adjustment of the balance on each side of a congested line or intersection (congestion management)

Congestion management is to a limited extent included in the report because transmission congestion limits the possibilities for utilizing the balancing resources. There is also a close connection to the operational balancing since the same resources often are used both for balancing and counter trading.

1.2 EXCHANGE OF RESERVES BETWEEN SEPARATE SYNCHRONOUS SYSTEMS

The issue of reserve trading is of particular interest with respect to the exchange between the Nordic countries Norway, Sweden, Finland and Denmark on the one side and Germany, the Netherlands and to a certain extent Poland on the other side. Firstly, because hydro generation has ideal characteristics for providing reserves compared with thermal plants. Secondly, because of the increasing integration of the Norwegian system with UCTE, specifically through the NorNed cable. Thirdly, because Norway probably will be a net importer of electrical energy in the coming years, which leaves more room for exporting balancing services.

Figure 1.1 shows the Nordic synchronous area, the HVDC interconnection to the European synchronous system and the balancing areas in Northern Europe.

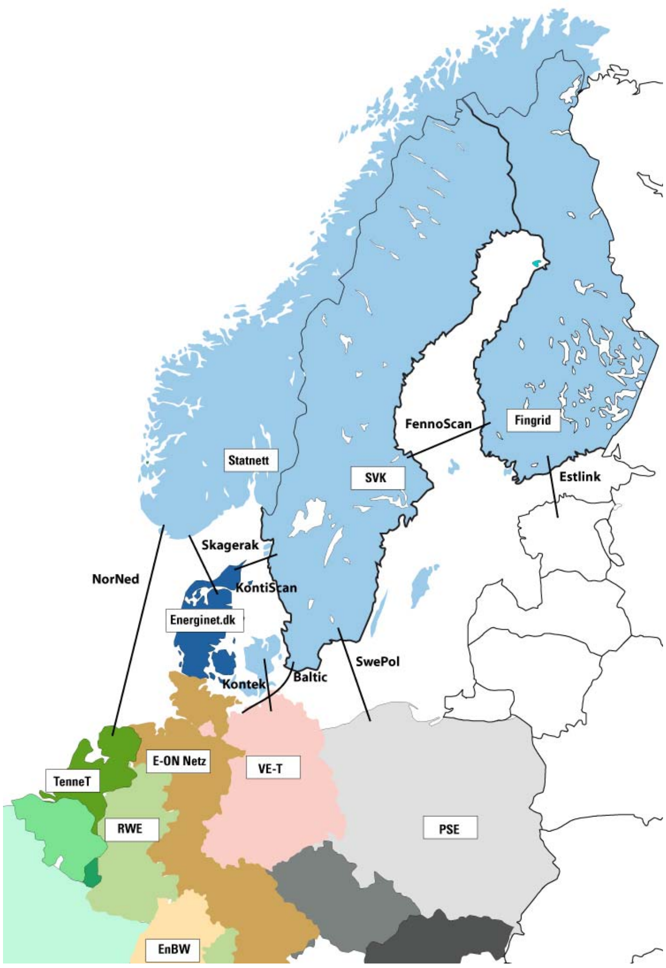

Figure 1-1 Balancing areas in Northern Europe

1.2.1 The Nordic System

The interconnected Nordic synchronous power system is made up of national subsystems, where the four TSOs, Statnett SF (Norway), Svenska Kraftnät (Sverige), Energinet.dk (Denmark) and Fingrid (Finland), are responsible for the operational reliability and the balance between production and consumption of electricity. The Nordic electric power market features direct trading among players (bilateral trade) and trading via the Nordic Power Exchange, Nord Pool.

Electricity production differs considerably among the Nordic countries. In Norway, nearly all electricity is generated from hydropower. Sweden and Finland use a combination of hydropower, nuclear power, and conventional thermal power. Hydropower stations are located mainly in northern areas, whereas thermal power prevails in the south. Denmark relies mainly on conventional thermal power, but wind power is providing an increasing part of the demand for energy.

Western Denmark is synchronous with the central European power system, and is interconnected with the synchronous Nordic system via HVDC links. Consequently, the frequency in Western Denmark is not affected by the Nordic imbalances. However, Western Denmark can contribute to the frequency control by delivering Regulation Power through the HVDC links. The balance management performed in the Western Denmark can also use the common Nordic balancing resources.

The operational requirements for the Nordic system are specified in a common System Operation Agreement [2], which among others comprises maintaining of sufficient operational reserves and regulation power in the Nordic system.

The Norwegian and the Swedish TSOs, Statnett and Svenska Kraftnät, have a special responsibility for conducting the balancing of the Nordic system, while the Danish TSO Energinet.dk manages the balance regulation of the Western Danish area, within its sphere of responsibility for the UCTE system, and in accordance with an agreement with EON Netz. Consequently, Energinet.dk has agreements with two balance areas; the UCTE system and the synchronous Nordic system.

1.2.2 The UCTE System

The *Union for the Co-ordination of Transmission of Electricity* (UCTE) [1] coordinates the operation and development of the electricity transmission grid from Portugal to Poland and from the Netherlands to Romania and Greece. The association includes the TSOs in 24 countries in continental Europe and provides a reliable market platform to all participants of the Internal Electricity Market (IEM) and beyond. The UCTE system was synchronized with the CENTREL (Czech Republic, Hungary, Poland and Slovakia) system in 1995 and the CENTREL countries are now members in UCTE.

The main power exchanges related to this study are: The European Energy Exchange EEX in Leipzig for the German market, the Amsterdam Power Exchange APX for the Dutch market and Towarowa Gielda Energii for the Polish market.

The HVDC links between the separate Nordic and UCTE synchronous systems makes the Dutch, German and the Polish control systems the most interesting from a Norwegian point of view.

The Dutch TSO TenneT is partner in the NorNed HVDC-link and is responsible for the balance management in the Netherlands. It is the task of the TSO to monitor the exchange with the neighbouring countries and to maintain the exchanges within the determined limits.

There are four German transmission operators: EnBW Transportnetze AG, E.ON Netz GmbH, RWE Transportnetz Strom GmbH and Vattenfall Europe Transmission GmbH; all are members of the UCTE. Within the scope of the German TSO cooperation (Verband Deutscher Netzbetreiber, VDN), the German TSOs have adopted a common transmission code [29], which includes the rules and regulations as well as the technical requirements for the provision of balancing and reserve power.

The Polish TSO PSE-Operator S.A. holds the License for Transmission and Distribution of Electricity on the territory of the Republic of Poland via networks consisting of 750 kV, 400 kV, 220 kV and 110 kV lines. The key objectives of PSE - Operator S.A. includes responsibility for the national security of electricity supply involving effective and efficient fulfilment of the national and international Transmission System Operator functions. PSE is responsible for the balancing of the polish power system, including imbalance settlement of system users.

Table 1-1 gives an overview of the Nordic TSOs (grey), the neighbouring UCTE TSOs and the respective Power Exchanges that are involved in the power exchange between the two separate synchronous systems.

Table 1-1 Overview of involved TSOs and Power Exchanges

	TSO / BM settlement responsible	Power Exchange
Norway	Statnett	Nord Pool
Sweden	SvK	
Denmark	Energinet.dk	
Finland	Fingrid	
Netherlands	TenneT	APX
Germany	E.ON Netz Vattenfall ET RWE Transportnetz EnBW Transportnetz	EEX
Poland	Polskie Sieci Elektroenergetyczne Operator S.A (PSE-Operator S.A)	Towarowa Gielda Energii

1.2.3 Market coupling

The ongoing process towards integration of the Day Ahead Markets in Europe through market coupling will influence the work for harmonisation of the balancing mechanisms over borders.

On 21 November 2006 the Trilateral Market Coupling ("TLC") between the Netherlands, Belgium and France was successfully launched. Market coupling is a way to integrate power markets in different physical areas while requiring minimal changes to the local arrangements. Under TLC the three power exchanges[1] continue to exist as separate legal entities with their own trading platform, contracts and clearing. The markets are nonetheless brought together by using the available transmission capacity to create a single regional market most of the time. The transmission capacity is used in an optimal way, enabling the best bids and offers to be matched from across the region. TLC replaced a two-step process: a daily explicit auction of transmission capacity followed by the day-ahead energy markets. This sequence has some inherent inefficiency. Market coupling integrates transmission allocation and energy trading, removing many of the inefficiencies at the day-ahead stage. Explicit auctions are still used for the monthly and yearly allocation of transmission capacity rights.

In line with a Memorandum of Understanding (MoU) signed on 6th June 2007, the Transmission System Operators and Power Exchanges work together on further harmonisation of a Central Western European (CWE) market coupling by January 2009. Key elements in the MoU include the development of a flow-based market coupling system between Germany, Luxemburg and the TLC region, and the requirement that this should also support market coupling with adjacent areas, in particular the Nordic region.

The TSOs and Power Exchanges are working together to realise the remaining steps; the operational trilateral market coupling (TLC) between the Netherlands, Belgium and France being the first. In addition, the TSOs and Power Exchanges of the TLC region are working on an extension of market coupling to Germany and harmonisation of the gate closure time of the concerned Power Exchanges by 2009.

It is anticipated that full market coupling between TLC and the Nordic Day Ahead Market will be achieved under the CWE MoU process, within the end of 2009.

It is the aim of the five project partners E.ON Netz, Energinet.dk, VE transmission, Nord Pool Spot and EEX to implement a market coupling system for more simplified cross-border electricity trading between Denmark and Germany by June 2008. After the establishment of the new market coupling system, all capacity on the Kontek interconnection and the daily capacity on the interconnection between Western Denmark and Germany will be utilised through an implicit auction. The annual and monthly explicit auctions on the interconnection between Western Denmark and Germany will continue. A new company, called European Market Coupling Company GmbH (EMCC) [4], will be established and located in Hamburg. EMCC is intended to provide specific services for the operation of market coupling to TSOs and power exchanges.

[1] APX (NL), Powernext (F), Belpex (B)

2 DEFINITIONS

One of the challenges within the area of system balancing is the use of terminology, which varies significantly between systems and countries. The same expressions are used for slightly different control actions, partly different words are used for the same type of reserves and the definitions are to some extent overlapping. It is therefore necessary to define the main terms in order to give a consistent description.

2.1 IMBALANCE

Three "types" of imbalances are relevant in the Balance Management context (project definition):

Power Deviation: Difference between production output and consumption. This deviation will cause a rise or fall in frequency leading to activation of the primary control (see next Section and Appendix B).

The electricity system is always in balance in the meaning that the load (included losses) is equal to the production. Electrical energy cannot be stored[2] and has to be used when produced. The offset caused by the Power Deviation will initially be compensated by the kinetic energy of the rotating generators and motors in the system.

R**egional/Area imbalance:** Deviations from exchange plan for the defined balancing area.

Keeping the physical balance in a large synchronous system (e.g. like the UCTE-system) is difficult without distributing the responsibility to the different balancing areas. The real time deviations from the exchange plans for the balancing area are therefore defined as imbalances to be handled by reserves. (These control actions have to be regarded as an aid to control the system and are not necessarily needed to maintain the quality of supply, which is shown by the practice in the Nordic system (cf. Section 4.2).)

Settlement imbalance: Deviations from exchange plans, in average over the settlement period, MWh/period, where the settlement period can be 60, 30 or 15 min.

In the market context the imbalance is related to deviations from planned exchange for the defined entity, e.g. the Balance Responsible Party (BRP) (cf. Section 3.1.2).

[2] The storage in hydro reservoirs is equal to storage of other energy sources like coal, oil, etc., and storage in batteries can only be done by charging, which is the same as consumption in the real time operation.

2.2 BALANCING CONTROL

The different control phases in Balance Management are defined in slightly different ways in the Nordic system compared to the UCTE system.

The operation handbook from UCTE regarding Load –Frequency control [3] gives the following definitions of the different stages of balancing control in the synchronous **UCTE system**:

The Primary Control **“**maintains the balance between generation and consumption (demand) within the synchronous area, using turbine speed or turbine governors.”

The Secondary Control “maintains a balance between generation and consumption (demand), within each balancing area / block as well as the system frequency within the synchronous area, taking into account the control program, without impairing the Primary Control that is operated in the synchronous area in parallel but by a margin of seconds. Secondary Control makes use of a centralised automatic generation control, modifying the active power set points / adjustments of generation sets in the time-frame of seconds to typically 15 minutes.”

The Tertiary Control “uses tertiary reserves that are usually activated manually by the TSOs after activation of Secondary Control to free up secondary reserves.”

Time Control: “Monitoring and limiting the discrepancies observed between synchronous time and universal time co-ordinated in the synchronous area.”

The control actions in the **Nordic system** (defined by the Nordel recommendations [2]) are somewhat different. The parallel to the UCTE Primary Control is called “*Momentary Control*” comprising “Frequency regulation” and “Momentary disturbance regulation”.

The parallel to the UCTE secondary and tertiary control is basically performed as the manual control based on the balancing resources available on the Regulation Power Market.
However, the Nordic manual control has the same purpose as the UCTE secondary and tertiary control, which is to compensate for the use of reserves used in the Primary Control. Actually, the wording “Secondary Control” is more and more used for the Nordic manual control.

The Time Control is in the Nordic system incorporated in the Secondary Control as deviation between synchronous and universal time, and is corrected by use of the manual balancing resources.

The technology used and the response requirements for the different control actions are basic in this context. The Primary Control in both systems is performed on generators based on the automatic frequency response defined by the droop setting on each generating set. The Secondary Control is required to change the output [MW] (set point) of the balancing resources so that the total production (or consumption) includes the reserve obligation, within 15 minutes.

We will therefore propose that the following simple definitions are used in this project.

Primary Control: *Automatic droop based frequency control*

Secondary Control: *Automatic and manual set point control*
(This definition includes the tertiary control that is used by UCTE, which means that both the automatic and manual activation of balancing resources are included, see section 2.3)

Time Control: *Manual set point control to eliminate the deviation between synchronous and universal time*

The technical background of primary and secondary control and a description the manual secondary control applied in the Nordic countries and the automatic generation control (AGC) used on the Continent are included in Appendix B.

2.3 BALANCING RESERVES

While UCTE uses the expressions primary, secondary and tertiary reserves, different terminology is used for reserves in the most relevant countries regarding exchange of balancing resources:

The following expressions are used in the **Nordic** system [2]:

Frequency controlled normal operating reserves (FCNOR) are automatically activated reserves "used for handling the small frequency deviations that appear during the operational hour"

Frequency controlled disturbance reserves (FCDR) are automatically activated reserves "by sudden frequency fall caused by grid or production failure"

Fast active disturbance reserves (FADR) are "the manual reserve available within 15 minutes in the event of the loss of an individual principal component (production unit, line, transformer, bus bar etc.) and restores the FCDR"

In the **Netherlands** [11] the following types of reserve capacity are used:

Regulating capacity is continuously controllable and is used for controlling the instantaneous system balance. It is procured by the TSO on contracts with certain producers, who through the contracts are obliged to offer this capacity. Other parties may also offer regulating bids.

Reserve capacity can be used for restoring the control area balance. Reserve capacity is primarily used to alleviate transmission constraints. It may sometimes be used to free some regulation capacity for frequency regulation.

Emergency capacity is used to re-establish the system balance when there is insufficient regulating of reserve capacity. It is procured through contracts with certain producers or BRPs as load shedding capability and availability.

In **Germany** the terms used for two of the reserve types are directly related to their purpose [15]:

Primary Control capacity (Primärregelleistung) is used for Primary Control.

Secondary Control capacity (Sekundärregelleistung) is used for Secondary Control, automatically activated by the affected TSO.

Minutes reserve (also called tertiary control capacity) is activated through telephonic request of the affected TSO.

The variation in definitions, even within the UCTE, makes it necessary to find a common nomenclature. In this project we propose to use the definitions from the reference model from ETSO [5]:

Frequency Containment Reserves (FCR) are operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. Activation of these reserves results in a restored power balance at a frequency deviating from nominal value. This category typically includes operating reserves with the activation time up to 30 seconds. Operating reserves of this category are usually activated automatically and locally.

Frequency Restoration Reserves (FRR) are operating reserves necessary to restore frequency to the nominal value after sudden system disturbance occurrence and consequently replace FCR if the frequency deviation lasts longer than 30 seconds. This category includes operating reserves with an activation time typically between 30 seconds up to 15 minutes. Operating reserves of this category are typically activated centrally and can be activated automatically or manually.

Replacement Reserves (RR) are operating reserves necessary to restore the required level of operating reserves in the categories of frequency containment (FCR) and frequency restoration (FRR) reserves due to their earlier usage. This category includes operating reserves with activation time from several minutes up to hours.

Table 2-1 summarizes the terminology of the different reserve categories.

Table 2-1 Reserve categories

Category	Nordel	Netherlands	Germany
Frequency Containment Reserves (FCR)	Frequency Controlled Normal Operation Reserve (FCNOR) Frequency Controlled Disturbance Reserves (FCDR)	Primary reaction	Primary Control capacity
Frequency Restoration Reserves (FRR)	Fast Active Disturbance Reserves (FADR) (Manually activated)	Regulation Capacity Reserve Capacity (Emergency Capacity)	Secondary Control capacity
Reserve Replacement (RR)		Reserve Capacity (Emergency Capacity)	Minutes reserves

2.4 BALANCING RESOURCES – REGULATION OBJECTS

The resources used for the Primary Control are without exception production units. FCR in hydro power is regarded as the most suitable resource because of the superior control ability compared to other production units. The major share of the FCR in the Nordic system comes from hydro power. In Continental Europe most of the FCR is placed in thermal plants.

The Secondary Control in the UCTE system is carried out by automatic generation control (AGC) on thermal plants. In Nordic system both production and consumption can take part in the Regulation Power Market, which is the source of the manual Secondary Control. These resources are also called *Regulation Objects*.

The tertiary control, which in practice exists only in the UCTE system is mainly performed by thermal plants, but also reducible loads in the heavy industry are used.

2.5 BALANCING REGION/AREA

In the reference model from ETSO [5] the synchronous systems are divided into two levels: ***Balancing Regions*** that can consist of several ***Balancing Areas*.**

The regional balancing function is able to cover one or more of the following features, as agreed or defined by the areas concerned (quote from [5]):

a) Support compliance with frequency and exchange deviation limits considering standards agreed
b) Respects interconnection capacities between the balancing areas
c) Uses commercial and technical characteristics for all necessary balancing resources in the region
d) Decides on which resource to activate and supports activation with areas concerned of resources made available by the balancing areas in merit order while respecting interconnection capacities between the balancing areas within the rules
e) Uses common imbalance pricing principles for the whole region
f) Generates same basic imbalance prices for the whole region if there are no congestions between the balancing areas (not final imbalance prices towards market parties but same basis)
g) In case of congestion between the balancing areas splits up the region in balancing areas thus creating different imbalance prices
h) Provides the basis for settlement of imbalance power between the areas

The area balancing function performs the following tasks corresponding to the relevant features of the regional balancing function (quote from [5]):

a) Agrees the region and the rules for the regional balancing function together with all area balancing functions concerned
b) Defines area balancing resources requirements
c) Procures balancing resources within the area subject to common regional procurement procedures
d) Provides information to the regional balancing function to account for congestions between areas
e) Activates balancing resources in the area supported by the regional balancing function
f) Uses common principles in settlement and pricing of imbalances
g) Settles imbalances (with market parties) within the area
h) Settles imbalances with other areas
i) Settles costs of activation of balancing resources in the area

Regulation area is an additional expression used in the Nordic system. These are the areas which the regulation market for the interconnected Nordic power system is divided into in order to manage possible capacity limitations (bottlenecks) on the transmission network. Potential bottlenecks will entail different regulation prices in the regulation areas. In Sweden, Finland, Western Denmark and Eastern Denmark, regulation areas normally correspond to the subsystems. In Norway, there are several regulation areas within the subsystem.

The regulation areas are normally defined by the Elspot areas, which means that regulation areas are defined if there is a price difference, and by that a declared bottleneck. In many cases however, declared bottlenecks have free capacity in the hour of operation. In this case the regulation objects are chosen without regard to the price areas, and prices in the separate regulation areas are defined as the same if congestion is avoided. This means that the regulation areas are merged during settlement.

2.5.1 Balancing regions and areas in Northern Europe

The balance regulation in the Nordic system acts as one Balancing Region, divided into two Balancing Areas:

- The synchronous Nordic System
- Western Denmark, which is synchronous with the Central European system.

The Netherlands consists of one balancing area.

Germany is divided in four balancing areas:

- The western part and an area in the south are controlled by RWE Transportnetz Strom (TNS) GmbH
- The south western part, controlled by E.ON Netz GmbH
- The central part, controlled by EnBW Transportnetze AG
- The eastern part, controlled by Vattenfall Europe Transmission GmbH

Usually there are no bottlenecks among the four German balancing areas, but many market participants argue that the existing transmission capacity should be used for power trading instead of transmitting control power.

Poland is one balancing area.

The different balancing areas are illustrated in Figure 1-1.

3 ROLES, PARTICIPATION AND REQUIREMENTS

3.1 ROLES AND RESPONSIBILITIES

The roles and responsibilities in the balancing market need to be defined explicitly and clearly. The most important actors are the Transmission System Operators (TSOs), the Balance Responsible Party (BRP).

3.1.1 TSO

The current laws and rules (EU legislation, Regional Handbooks and Grid Codes like the UCTE operation handbook and the Nordic Grid Code) place the responsibility for the operational security of supply upon the TSOs. Consequently the TSOs are responsible for balancing, congestion management, grid operation, network restoration, etc. The special responsibility for balance management applied in the areas relevant to this study is summarized below.

Nordic System

The system operator has to be a non-commercial organization, neutral and independent with regard to the market participants.

The four TSOs are presently working towards standardisation on the balancing services in the system, which has been specially addressed as one of the preconditions for a future Nordic retail market. The TSOs have already agreed on having a common list of balancing resources and the Area control error is removed as control criterion. The present focus is on harmonizing the balance settlement in the four countries, which includes pricing models and a future system where the players can be served on a one-counter basis.

Supervisory control Nordic system

Sweden and Norway represent approx. 75% of the annual consumption of the synchronous system. The Parties have agreed in the Nordic system operation agreement that Svenska Kraftnät and Statnett will thus have the task of maintaining the frequency and time deviation within set limits. Fingrid and Energinet (for Eastern Denmark) will normally only activate reserves after contacting Svenska Kraftnät. Energinet will exchange regulating power for Western Denmark with the Nordel synchronous system after contacting Statnett.

Netherlands

TenneT Holding B.V. was established to create a clear distinction between regulated and non-regulated tasks. The Dutch state (by the ministry of finance) is 100 % owner of TenneT Holding B.V. The limited company TennetT TSO B.V. is created as the owner and operator of the national transmission grid and the 150 kV network of the province of Zuid-Holland. As of 1 January 2008, TenneT will also become the grid operator for all 150 and 110 kV grids in the Netherlands.

According to their web site, TenneT TSO has a duty to monitor the continuity and security of the electricity supply in the Netherlands, 24 hours a day, 365 days a year. In addition to administering the national transmission grid and safeguarding the reliability and continuity of the Dutch electricity supply, TenneT provides services and performs duties aimed at developing the electricity market and ensuring that it functions properly. TenneT also provide services that support free-market operation and further the development of a sustainable energy supply system.

It is the task of the TenneT to monitor the exchange with the neighbouring countries and to maintain the exchanges within the determined limits. In the Operational Rules [11] this is described slightly more specific as “unplanned exchanges with neighbouring countries, taking into account frequency deviations” or the Area Control Error, ACE.

TenneT is party to all UCTE policies and is committed to compliance with these policies.

Germany

Germany is divided in four balancing areas, each with their own TSO, cf. Section 1.2.2. It is the task of the German transmission operators to maintain a permanent balance between power generation and demand in their balancing area, and provide balancing energy to the balancing groups (cf. Section 3.1.2) from the Secondary Control power and minutes reserve kept available [15] and [16] §13. There is close cooperation among the TSOs in order to minimize the total amount of control power that is required.

Poland

The Transmission System Operation was separated from the mother company Polskie Sieci Elektroenergetyczne by the establishment of PSE-Operator S.A. on July 1st 2004. The transmission assets were leased to TSO who also has the responsibility for power system operation and security.
PSE-Operator is responsible for the balance management for the country, which is operated as one Balancing Area. The control actions are performed in accordance with the recommendations from UCTE [3].

Supervisory control UCTE

The National Control Centre of Switzerland in Laufenburg supervises the total balance and the time deviation caused by frequency fluctuations. Because of its supervisory role, Laufenburg may over steer the area based Secondary Control in cases where this is necessary for the UCTE system as a whole.

3.1.2 Balance Responsibility

Nordic System

For historical reasons there are some differences in the way the Nordic TSOs define the Balance Responsible Party (BRP). The harmonisation process implies, however, a drive towards a common understanding of the main aspects in this context.

In principle each of the market players is responsible for balancing supply and demand. A player may ask another player to take over his responsibility and act as BRP on his behalf. The BRP must enter into a contract with the national TSO.

The BRP is responsible for organising his purchases and sales and bears the economic responsibility for the overall balance for those he is representing. The BRP often has regulation resources at his disposal, which means that he can act as a player on the regulation power market. However, this is not a requirement for being a BRP.

The number of BRPs varies from country to country from tens in Finland to hundreds in Norway.

Netherlands

Program responsibility is the central issue with respect to balance management in the Netherlands. It is the responsibility of each Program Responsible Party (PV in Dutch, we will further use Balance Responsible Party or BRP as in Nordel)[3] to keep its balance within each Program Time Unit of 15 minutes (PTE in Dutch, we will further use PTU). Everybody who is connected to the network must either be a BRP or have an agreement with an approved BRP who will fulfil the program responsibility function on his behalf.

Germany

The German system is centred around the so-called balance groups (Bilanz kreis) [17] § 4. Within each control region there must be at least one balance group (in practice there are many). Each balance group has a responsible part for balancing (BRP). Every consumer and producer must have an agreement with a BRP. The BRP is responsible for a balanced program for each 15 minute period within the day (like for the Dutch case we will call this PTU).

[3] The Dutch System Code makes a distinction between BRPs with a trade approval and BRPs with a complete approval. The differences between these are outside the scope of this report.

3.2 PARTICIPATION

Nordic System

Both producers and large consumers participate in the balance market, but almost all regulation is done by the producers. Participation is not mandatory, but in difficult situations the TSO has the right to require that all available regulation capacity is made available in the Balance Market, cf. [25] § 5-A1. An incentive for participation is established through the Reserves Option Market, cf. Section 3.2. Successful bidders in this market are obliged to offer their capacity in the Balance Market.

Netherlands

The major part of the frequency restoration capacity exists of generation capacity that can be regulated up and down, made available by owners of more than 60 MW production capacity on a mandatory basis according to paragraph 5.1.1a.1 in the Dutch Grid Code [10]. Owners of less than 60 MW of production capacity may offer capacity on a voluntary basis. The System Code contains additional clauses about which resources the TSO should utilize in the case it is not possible to maintain the balance with normally available resources: reduction of export, use of units larger than 5 MW and ultimately involuntary shedding of demand.

All owners of units larger than 5 MW that are connected to the grid must inform the TSO about installed capacity and fuel type for each location separately on a quarterly basis.

Germany

Every generation unit with a rated capacity ≥ 100 MW must be able to provide Primary Control capacity [12]. The TSO has the right to release specific unit from this obligation. Units with a rated power < 100 MW can participate in Primary Control after agreement with the TSO.

Producers from the Austrian balancing areas of TIRAG and VKW have also participated in the German market for minutes reserve.

All bidders must pass a pre-qualification procedure (PQ) based upon the rules of the UCTE [3] as well as upon common rules of the German grid [12]. Once qualified, the bidder and the TSO conclude a framework agreement.

Poland

Conventional thermal units of 100 MW or more are obliged to participate in primary and secondary control.

Other generators that are able to fulfil the requirements are eligible to participate in primary, secondary and tertiary reserve. In this sense the unit shall be equipped and maintained according to the requirements by Instruction of Transmission System Operation and Maintenance.

Moreover in the case of tertiary reserves the generator has to join the dedicated IT system. The reserve is remote, manually activated as unit load set points, coming from load dispatch based on generator bids and sent via the IT system.

Consumers do not participate in any type of control.

3.3 VOLUME REQUIREMENTS

3.3.1 Nordel

In the Nordic system the active reserves are as specified in ch. 2.3 divided into the Frequency Controlled Normal Operation Reserve (FCNOR) and the Frequency Controlled Disturbance Reserve (FCDR), which are related to the defined Frequency Containment Reserve (FCR) and the Fast Active Disturbance Reserve (FADR), which is related to the defined Frequency Restoration Reserve (FRR).

The FCNOR shall be at least 600 MW at 50 Hz for the synchronous system and shall be completely activated at frequency f =49.9 / 50.1 Hz. The reserve requirement is distributed among the four countries according to annual total consumption the previous year. The distribution of the FCDR is distributed according to the dimensioning fault[4] within the respective sub system, and at least 2/3 of the FCDR should be placed within the sub system. Table 3-1 shows the distribution of FCR which was applied in 2006 [2].

Table 3-1 Distribution of FCR in the Nordic system [MW]

	FCNOR	FCDR	SUM FCR
Norway	203	317	520
Finland	137	228	365
Sweden	237	322	559
Eastern Denmark	23	153	176
Sum	600	1020	1620

The size of the FRR (FADR) is determined by the individual subsystem's assessment of local requirements. Bottlenecks on the network, dimensioning faults and similar are included when assessing this. The forecast error, which is the potential deviations from the consumption forecast due to change in temperature etc, is included only in the Norwegian requirements.

[4] Nordel definititon: Dimensioning faults are faults which entail the loss of individual major components (production units, lines, transformers, bus bars, consumption etc.) and entail the greatest impact upon the power system from all fault events that have been taken into account.

Table 3-2 Distribution of FRR in the Nordic system [MW]

	Ref dim. fault	Ref. forecast error	SUM FRR
Norway	1200	800	2000
Finland	865		865
Sweden	1220		1220
Eastern Denmark	580		580
Sum	3865	800	4665

3.3.2 UCTE

The provision of primary control power to any control area is shared mutually by all UCTE-member TSOs and is allocated based on their annual production volumes. 3.000 MW of primary control capacity is procured. The UCTE argues that this amount hedges against the simultaneous trip of two generation units each with 1.500 MW (n−2 criterion), or against the loss of a line section or busbar. Considering the reference incident of 3.000 MW (loss of generation or load), the primary control reserve of each control area must be fully activated within 15 seconds in response to disturbances ΔP of less than 1.500 MW, and within a linear time limit of 15 to 30 seconds in response to a ΔP of 1.500 to 3.000 MW respectively.

According to the UCTE, the minimum secondary reserve can be calculated with the following empirical formula without distinguishing between incremental and decremental reserves:

$$R_{sec} = \sqrt{aL_{max} - b^2} - b \qquad [\mathrm{MW}]$$

with R = recommendation for Secondary Control reserve [MW]
Lmax = maximum anticipated load for the balancing area [MW]
The parameters a and b are established empirically. For the UCTE the values are a = 10 MW and b = 150 MW.

Netherlands

The Netherlands represent a share of 3.6 % of the total production in the UCTE. Consequently, the minimal primary reserve requirement is 3.6 % of 3000 MW or 110 MW.

The secondary reserve requirement for the Netherlands based on the equation for R_{sec} above results in approximately 300 MW, based on a peak load of 17500 MW.

Germany

Germany represents a share of 22.4 % of the total production in the UCTE. Consequently, the minimal primary reserve requirement is 22.4 % of 3000 MW or 673 MW for 2007.

The Table below shows annual maximum load for each balancing area and Germany as a whole, the resulting recommended minimum secondary reserve capacity and the effectively provided capacity.

Table 3-3 Secondary reserves in the 4 German balancing areas [22]

TSO	Maximum Load		Recommended min [MW]	Effectively provided [MW]	
	Date	[MW]		Incremental	Decremental
EnBW	10-01-2006	19971	±322	+720	-300
E.ON	06-11-2006	22985	±353	+800	-400
RWE	30-01-2006	32382	±430	+1230	-920
VET	21-02-2006	14970	±265	+580	-580
Total	06-11-2006	74793	±728	+3330	-2290

Note that the total peak load for Germany is considerably lower than the sum of the peak loads for each balancing area because the peak loads are not coincident. As a result, the sum of the individual recommended R_{sec}'s for each balancing area according to the equation above also exceed the recommended R_{sec} for Germany as a whole.

The recommended minimum amount of tertiary control in Germany can be calculated by subtracting the recommended minimum Secondary Control from the largest generation capacity within the balancing area. Thus, the system is protected against the tripping of the largest generation unit or its network disconnection. However, the UCTE's recommended values do not account for Germany's wind generation. Between 2000-2006, the country's installed wind capacity expanded from approximately 6.000 MW to over 20.000 MW (Deutsches Windenergie-Institut, 2007). The German TSOs argue that the amount of power reserves needed for balancing wind shortfalls must increase as well. In fact, the amount of minute reserve power, which is often used for balancing the wind shortfalls, is distinctly higher in the balancing areas of E.ON, RWE and VET (where installed wind capacity is greatest) than in the EnBW balancing area. However, this difference could also be caused by the fact that EnBW utilizes Secondary Control power more than tertiary control. Unfortunately, detailed quarter-hour values about the commitment of Secondary Control in the four balancing areas are not publicly available.

3.4 RESPONSE REQUIREMENTS

3.4.1 Nordel

The activation of the FCNOR and FCDR is dependent of the turbine regulator settings The TSO are responsible for placing requirements for the droop and time constants. The following time requirements apply in the event of a frequency drop to 49.5 Hz caused by a momentary loss of production:

- 50 % of the frequency controlled disturbance reserve in each subsystem shall be regulated upwards within 5 seconds
- 100 % of the frequency controlled disturbance reserve shall be regulated upwards within 30 seconds.

The manual FRR are activated by the TSOs according to the common merit order regulation list and the ΔMW called for up or down regulation should be available within 15 min from the time of notice.

3.4.2 UCTE

The Primary Reserve of each balancing region/area must be fully activated within 15 seconds in response to disturbances ΔP of less than 1500 MW, or within a linear time limit of 15 to 30 seconds in response to a ΔP of 1500 to 3000 MW. As a minimum requirement, the deployment time of the Primary Reserve must be consistent with the curves plotted in Figure 3-2, which illustrates the minimum deployment of primary control power as a function of time and the size of the disturbance ΔP.

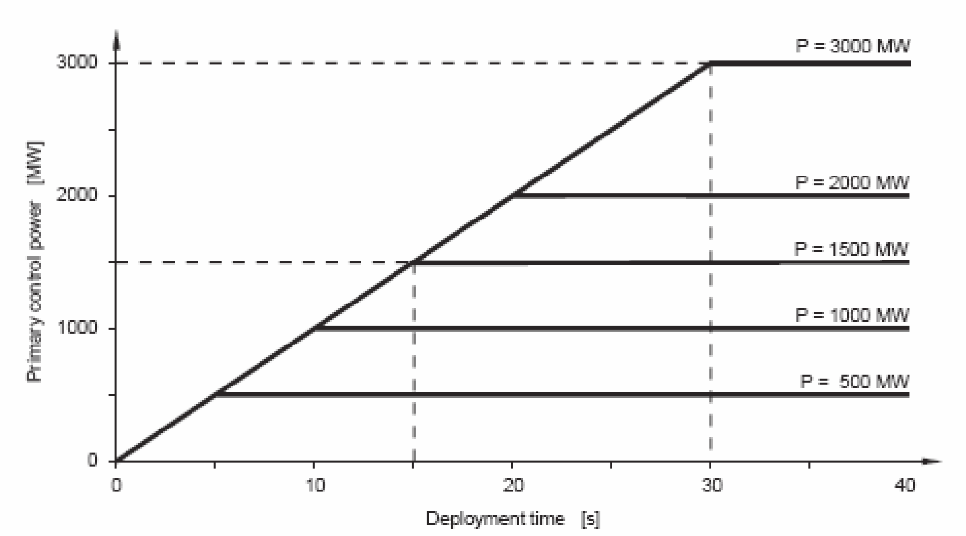

Figure 3-1 Deployment of primary reserves [6]

The requirement for the activation of FRR differs between the different sub systems.

Netherlands

Regulating capacity must have an up- and downward regulation speed of at least 7 % per minute. The reaction time shall be no more than 30 seconds. Regulating capacity is used for Frequency Containment Reserves and Frequency Restoration Reserves. Capacity used for Frequency Restoration Reserves shall be fully activated within 15 minutes.

Reserve capacity has weaker requirements to reaction time and regulation speed than regulating capacity, but the exact values are not clear from the Code [11] or the additional rules.

Germany

FCR (primary control) shall be activated within 30 seconds, and the time period per single incident is between zero and 15 minutes.

The FRR (secondary control) shall be activated within 5 minutes. The time period per single incident is between 30 seconds and 60 minutes. The FRR shall be fully activated within 15 minutes and be sustainable in up to 60 minutes.

The RR (tertiary control) shall be activated within 15 minutes through telephonic request of the affected TSO. A request shall be made at least 7½ minutes before the beginning of the next quarter of an hour. The time period per single incident is from 15 minutes up to 4 quarters or up to several hours in the event of several disturbances.

The time frame of control energy usage is shown in Figure 3-2.

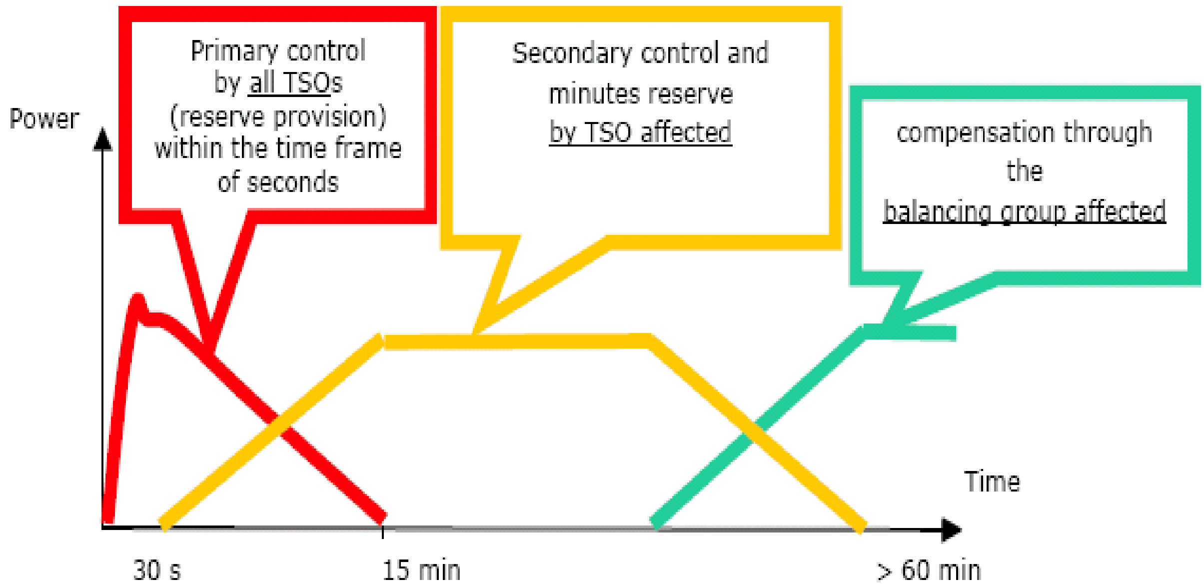

Figure 3-2 Time frame of control energy usage in Germany [15]

The Figure 3-2 shows that according to the German market rules, TSOs are responsible for the provision of reserves only within the first 4 quarter hours after occurrence of a power imbalance, e.g. after a power station failure.

To utilize the output of a generator for Secondary Control, its rate of change must meet specific values. The rate of change for oil- or gas-fired units is in the range of 8% per minute. Reservoir power stations, such as pumped storage plants, must have rates between 1.5 and 2.5% per second, whereas for hard coal- and lignite-fired plants, rates from 2 to 4% per minute and 1 to 2% per minute respectively are sufficient. The maximum rate of change for nuclear plants is approximately 1 to 5% per minute [22].

4 BALANCE MANAGEMENT IN A MARKET CONTEXT

In the existing European electricity markets there appear to be a common understanding of the nature of the balancing market and mechanisms where they fit in. However, there are differences in the timing of the different services with regard to where they start and end. Most important in this context is the interactions between the balancing markets and the intraday markets.

The overall trading timetable extends from months or years before a trade is to be executed, to 'gate closure', further to the moment the trade is to take place ('real time'), and then beyond this in terms of settlement of the trade. By gate closure (day ahead, or one hour before real time, or possibly even shorter time), generation and load parties must notify the TSO of their expected physical positions at real time. Additionally, within the balancing market they can submit bids and offers of the extent to which they are willing to be paid to deviate from these positions and what has to be paid for this service.

Following gate closure, the TSO will make calls on the bids and offers of generation and load in order to balance the system at the least cost. Where intra-day markets exist, TSOs will need to take into account further restatements of bids and offers when making such calls.

A general overview of the interaction of balancing, which is the responsibility of the TSOs, and other markets in the Nordic system, operated by the Power Exchange (PX) Nord Pool, is shown in the Figure 4-1 below.

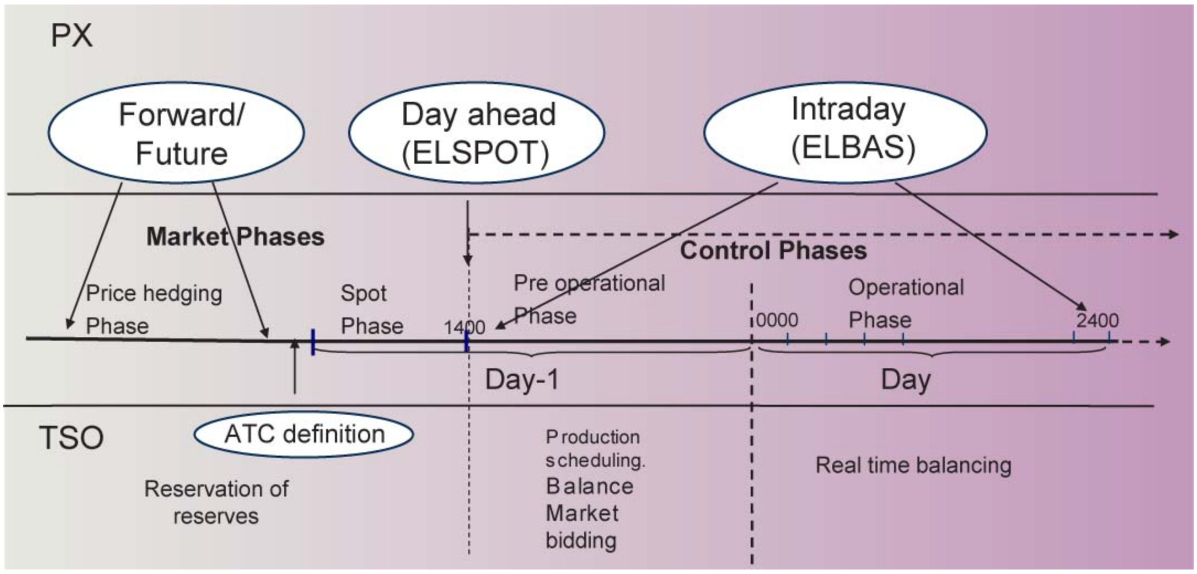

Figure 4-1 Transition from market to physical operation in the Nordic region

The *market phases* start with bilateral contracting and financial trading and end with the spot market settlement every day at noon. The available transmission capacity (ATC) for the different intersections is defined by the TSO before the opening of the Elspot market. The *control phase* starts with the *pre operational phase* where production scheduling is carried out by each producer and the market players submit bids for the real time balancing market, which is used in the *operational phase.* The *intraday trading* takes place in the preoperational phase up to one hour before operation. Procurement of balancing resources in advance, or *reservation of reserves*, is done in the Market phases.

In this Chapter we will discuss a number of central issues related to balancing markets and their interaction with each other and with other markets like the intraday markets. Information regarding Poland is only partly available.

4.1 RESERVATION OF RESERVES

The establishment of a reserve market with long-term payment for availability has two effects:
- The availability of sufficient secondary reserves is ensured.
- The necessity to keep reserves is reflected in the spot price.

Following is an overview of the present advance procurement in the different systems.

Nordic System

Norway has since 2000 bought "options" for balancing resources from producers and consumers. A market based *Power Reserves Acquirement* [21] was introduced by the TSO. This product represents a kind of medium term ancillary service market where both producers and consumers are allowed to bid in reserves. The new element introduced by this product was payment for availability. The market-clearing price was determined as the price of the last offer accepted. A market participant with a succeeding offer in this reserve market is obliged to make the offered quantity available in the Regulating Power Market.

This arrangement has later been developed to the present Reserves Option Market (ROM or RKOM which is the Norwegian term). The regulation offers selected in the bidding process receives an option payment [NOK/MW period]. The time resolution of market is one week. Statnett makes an evaluation of the requirements for the following week based on a forecast of the power balance and an assessment of the need for reserves. The selection of offers is primarily based on the bid prices within the predetermined bidding areas. All accepted bids receive the price of the highest offer accepted.

Denmark has adopted a similar Option Market as the Norwegian.

In *Sweden* and *Finland* reserves are procured in advance through bilateral contracts.

Netherlands

TenneT has annual contracts with specific producers obliging them to bid secondary reserves. Note that the obligation mentioned in Section 3.1.2 does not require producers to provide for each unit's ability to regulate up- and downwards, neither does the obligation require producers to set aside capacity for reserve purposes.

In total these contracts amount to 300 MW of capacity, based on UCTE recommendations [3]. The opportunity to sell regulation capacity on contract should motivate producers to necessary investments to ensure their units' capability to participate in regulation.

Germany

There are half-yearly auctions for primary and Secondary Control capacity [15]. For the time being there are separate auctions for each of the four TSOs, but it appears to be the intention to establish a common auction for all control capacity [19]. The present separate auctions probably have common rules, but it is difficult to find exact details on the TSOs' web sites.

The amount of reserve power that is effectively needed for balancing/regulation by each TSO cannot be precisely defined in advance, so each bidder must bid a specific amount of capacity for which it holds its generation unit(s) ready for supply. Therefore, the bidder is paid the demand rate, which has the character of an option fee. If the generation units are effectively called up to deliver energy, the bidder is paid the energy rate in addition to the demand rate.

4.2 COMMON BALANCING MARKETS

Nordic System

The BRPs submit bids for regulating power to their respective TSO who transfers the bids to the common TSO information system (called NOIS) for the common balancing market for the whole balancing region plus Western Denmark. The bids are arranged in a joint list for regulating power and are used in price order, with the exception of bids confined behind a bottleneck. For each hour, the balancing price is determined in all Elspot (Nord Pool market) areas. The balancing price is set at the marginal price of activated bids in the joint list. When bottlenecks do not arise during the hour of operation, the prices will be equal.

Bottlenecks caused by a reduced transmission capacity to/from an Elspot area, after Elspot clearing but before the operational hour, are managed using counter trading (two-sided so called "special" regulation, i.e. activation of both up and downward regulation bids for network reasons). Activation of bids for management of bottlenecks within the operational hour is done in one direction only. All bids that are activated for network reasons get the activation type "special". Activation of bids (regulation) for network reasons shall not affect the balancing price calculation.

When regulation is done for internal network constraints in an Elspot area, bids are used from the common Nordic merit order list of regulating power bids, for rectifying the network problem in the subsystems. When choosing a bid, attention must be paid to both the price and the effectiveness of the activation of the regulating object behind the bid. After the network constraint

has been rectified there might be a deviation in frequency caused by the network constraint regulation. Frequency will then be restored by normal balancing operation.
When regulating for network reasons on the border between Elspot areas, the cheapest bids are normally used in the subsystems rectifying the network problem.

Netherlands

The Netherlands constitutes one balancing region, and all reserve markets are operated within the whole balancing region. If bottlenecks occur, they will normally be handled using Reserve Capacity, cf. Section 2.3.

Each BRP must each day before 08h00 provide the TSO with a plan for the exchange with neighbouring countries (“IET planning”) for the next day (e.g. on Monday the IET planning for Tuesday must be prepared). Depending on the state of the interconnections, the IET planning may be approved by the TSO or returned to the BRP with a requirement of modification.

Before 14h00 each day, the BRP must provide its *energy program* (E-program) to the TSO, three hours after gate closure of the APX day ahead market at 11h00. The E-program includes the result of the IET-planning. The TSO verifies the consistency of the E-programs for all BRPs and takes appropriate action if there are inconsistencies. E-programs may be changed up to one hour before actual operation, but changes must be consistent between BRPs. E.g. a producer who looses a unit because of an outage may contract another producer to compensate for the loss of production. Assuming both producers are also BRPs, they will both report a change in their E-program to the TSO.

The BRPs must also provide the TSO with a *transport program* (T-program), specified in Section 5.1.1.2 and 5.1.1.3 of [10] (where it is called transport forecast) within the same deadline. T-programs exist of hourly MW values (5.1.1.3 in [10]) for all nodes specified by the TSO. Grid owners must also specify Mvar values. The goal of the T-programs is to make it possible for the grid owners and the TSO to verify the feasibility of the resulting load flows with respect to the operational criteria of the grid.

After the submission of the E- and T-programmes within 14h00, there is little the market can do until approval of the E-programmes by TenneT at 17h30 (intended, mostly prior to that time, but sometimes later). During this interval the grid operators have the exclusive right to relieve grid constraints by redispatching using the bids of regulating and reserve power. Only after this interval market parties can exchange new E-Programmes for the next day, and send in/redraw bids; resulting updates of T-forecasts are mandatory.

Germany

The German balancing region case is a typical and so far with Europe unique example of a model for trading of minutes (tertiary) reserves across balancing areas. This example includes the (balancing) areas in Austria that belong to the German balancing region (TIRAG and VKW Netz). However, it should be noted that the minutes reserves are used only few hours annually.

A reserve provider of control power (BRP) can take part in each of the 4 German markets for balancing services, i.e. independent from his physical connection to the grid within Germany. In the balancing region the different balancing areas have the responsibility for their own balance, and in addition RWE TNS has the responsibility in front of the other UCTE balancing regions for balancing the German balancing region. The favourable bidders are chosen according to the merit order, and the power reserves are applied when needed. The last step of the procurement process settles the costs of provision with the respective market participants and balancing group managers.

The settlement of the exchange of electricity between balance groups is based on Operational Plans (Fahrplan) [17] § 5. The Operational Plans must be delivered to the TSOs within 1430 the day before. The Operational Plans must be complete and balanced, which allows for the establishment of a balance for the whole control region. Operational plans can be changed up to three quarters of an hour before actual operation. The TSO has the right to refuse such changes, but must give a reason for the refusal.

Operational Plans that only affect interactions within the same balancing area can be changed afterwards up to 16h00 the working day after the day of operation.

The BRP should notify the TSO of the planned production within its balance group for the next day of all units larger than 100 MW within 1430. This notification is used by the TSO for network security purposes, and is of no significance for settlement [18].

Poland

Primary and secondary reserves are purchased in accordance of bilateral agreement on the obligatory basis. Tertiary Reserves (>15 min) are purchased on market conditions (competitive balance mechanism). The reserves are activated on the basis of merit ordering. The primary/secondary reserves on the basis of purchase price - depending on bilateral agreements, tertiary reserves on the basis of balancing market bids; the prices differs for different hours.

4.3 INTRADAY MARKETS

Intraday markets (IDM) are by ETSO [23] defined as the possibility for transactions between market parties after gate closure of the day ahead markets. The purpose of the IDM is according to the same source: To facilitate new market segments under secure network conditions and to enable and encourage self-balancing of the market parties in relation to an incentive compatible imbalance pricing scheme.

Nordic System

The intraday market in the Nordic system, ELBAS, is a standard product at Nord Pool for intraday trading from the closing of Elspot up to one hour before the hour of operation. The ELBAS market opens in principle after the distribution of the Elspot prices for the day ahead at 14h00 (17h00 in Denmark) and closes one hour before the hour of operation. This means that the ELBAS is open around the clock with a time horizon from 10 to 34 hours, which enables continuous trading with contracts that lead to physical delivery for the hours that have been traded on the Elspot market. The traded Elbas products are one-hour long power contracts traded by the balance responsible parties in order to reduce the imbalance.

Norway has so far been opposed to the need for such trade, which obviously is more important in countries with high share of thermal power. However, as a part of the harmonisation efforts in Nordel, Norway has decided to join the ELBAS market from second quarter 2008.

In effect will this market trade free capacity that alternatively would have been available on the common regulation list. This means that there will be less regulation bids on the list, but there will still be a reliable regulation merit order list before the closure of the ELBAS market, i.e. one hour before operation.

Netherlands

APX offers three tradeable intraday products:

- APX Intraday PTE, for a time unit of 15 minutes (called PTU in this report) tradeable up to 2 hours before delivery.
- APX Intraday 1H, for a time unit of 1 hour, tradeable up to 90 minutes before delivery.
- APX Intraday 2H, for a time unit of 2 hours, tradeable up to 90 minutes before delivery.

The main trading session for each of these products is from 07h30 to 18h00 on Monday to Friday and from 09h00 to 14h00 on Saturdays and Sundays.

Germany

EEX operates an intraday market that in principle is open 24 hours on any given day of the year [7]. The time unit is one hour. Tradeable delivery hours are the remaining hours of the current trading day and all the delivery hours of the following trading day from 15h00 of the current trading day. Trading for one delivery hour ends 75 minutes before the commencement of physical delivery.

All intraday orders have to be “limit orders”, i.e. they must have a specified price limit (as opposed to the day ahead market, where it is possible to use “unlimited orders”). It is also possible to trade “combined block orders”, which are products for a number of consecutive hours, which are dependent on each other for execution.

4.4 GATE CLOSURE

"Gate closure" indicates the time when bidding in a market is closed. E.g. when gate closure for the day ahead market is 12h00, this means that it is not possible to send offers and bids to this market after 12h00. The gate closure time for the different markets is a basic issue with regard to harmonisation.

Nordic system

- Day ahead market (Elspot): 12h00
- Intraday Market (Elbas): Continuous trading from 14h00, (17h00 in Denmark) until one hour before operation
- Balancing market: Bidding within 19h30, changeable until one hour before operation.

Netherlands

- Day ahead market: 11h00
- Intraday Market: Trading 7h30-18h00 same day delivery trade, 12h00-18h00 next delivery day, cf. Section 4.3.
- E-programmes, T-programmes, Balancing market (initial bids, changeable until one hour before operation [11]): 14h00

Germany

- Day ahead market: 12h00
- Intraday Market: Continuous trading, cf. Section 4.3.
- Balancing market:
    - Primary and Secondary Reserves: bi-annual auctions
    - Minutes Reserves, auction opening for next day delivery [22]:
        - VET: 09h00
        - E.ON: 10h30
        - EnBW: 13h30
        - RWE: 15h00

4.5 PROCUREMENT AND PRIORITIZATION

4.5.1 Primary Control - FCR agreements / trade

The provision of primary control services used to be mandatory both in the Nordic and the UCTE systems. Special agreements which include economic compensation have, however, become common during the resent years. In some countries the FCR is even traded on commercial basis.

Nordic System

Special agreements are applied between the provider of primary control and the TSO in the different countries. There has, however, been a trading mechanism of FCNOR and FCDR between the TSOs for a while [2]:

The trading is carried out bilaterally between the TSOs[5]. The respective TSO informs each other on a daily basis after the Elspot has closed regarding surpluses of frequency response, volume and prices that can be offered to the other system operators. If trading involves transit transmission through a subsystem, the system operator in whose network the transit transmission will take place, shall be informed before making the agreement. In the event of selling to several system operators, all will pay the same price, the marginal price.

Nordel has for some time discussed a new Nordic market for FCR. There have however been difficulties with regard to achieving a common understanding of the pricing mechanisms needed and the effort have been put to rest. The Norwegian TSO, Statnett, has, however, decided to develop a FCR market for Norway with the following properties:

- Weekly market with day and night products
- Daily market with hourly bids
- Marginal pricing
- Weekly settlement

The Norwegian market for FCR was opened for trade 18 January 08.

Netherlands

According to the System Code [9], all producers are obliged to provide primary reserves. More precisely, plants over a certain capacity are mandatory equipped with capability to provide primary reaction, and plants over a certain capacity are mandatory required to provide primary reaction, without compensation. TenneT has a coordinating and monitoring function, and has the right to test the facilities with respect to the technical requirements. Because there are no other incentives, TenneT has considered the option of contracting primary reserves from specific

[5] Norway has for many years sold FCR to Sweden. In 2007 trade was also accomplished with Energinet.dk in a period with interruption of a basic production unit on Zealand. Finland has also periodically demand for reserves related to the status of the link to Russia, which comprises exchange of reserves. The exchange of FCR with Finland started in 2005.

producers, as an alternative to stronger enforcement by the Regulator. It would still be mandatory for all generator units to have the primary control equipment installed.

Germany

There is one biannual auction for Primary Control capacity for both upward and downward regulation within each balancing area. Offers include one capacity price for up- and downward regulation (€/kW), as well as technical data like the unit, connection busbar and droop. Bids are prioritized according to price.

On August 30, 2006, the Federal Network Agency (FNA) published desired key points for future primary control auctions [22]. The FNA suggested that the bidding periods for primary control power be reduced from 6 months to 1 month; the minimum bid size be set at 10 MW with a bid increment of 1 MW; and the entire amount of primary control power be tendered in a common auction. In an effort to improve market transparency, the FNA also suggested extending the obligations to publish.

4.5.2 Secondary Control – FRR agreements / markets

There are two main options for obtaining needed reserves for frequency restoration:
- Bilateral contract between the provider and the TSO
- Adequate commercial services or organized regulation power markets

Nordic System

A joint list of bids for regulating power is compiled by the TSOs, in order of price, containing bids from both the synchronous system and Western Denmark, see Figure 4-2 . The list is based on the regulation offers and bids from market players given to the respective TSOs. A preliminary list is put together the evening before[6] for up and down regulation for each hour the next day (00-24). The actors are however, allowed to adjust their bids up to one hour before operation. This merit order list is used consistently if there are no physical congestions in the system. The merit order will be departed when congestions occur and the power system will be divided into regulation areas with different process.

[6] The TSOs are feeding the Fingrid central with the regulation objects, price and volume, from each country

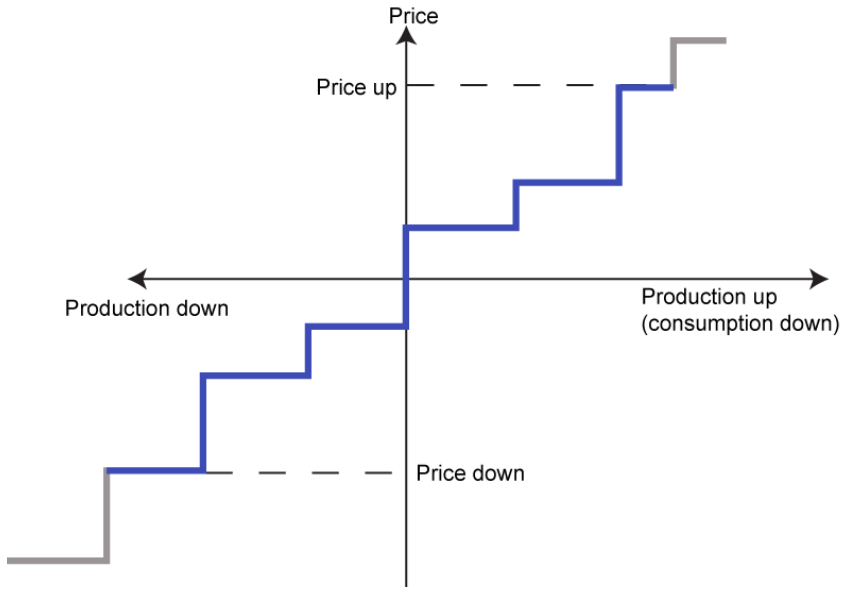

Figure 4-2 Balance market merit order list

During the hour of operation, activation of bids is initially carried out for network reasons and then, if necessary, for balancing, i.e. to maintain the frequency. Activation of bids for network reasons within the operational hour needs only to be in one direction.

According to the Nordic system operations agreement, the TSO in Norway, Statnett (SN) and the TSO in Sweden, Svenska Kraftnät (SvK), are jointly responsible for frequency and activation of FRR. Finland and Denmark provide bids for the common list. Depending on the frequency situation SN and SvK agree, over the phone, on necessary steps. SvK has the responsibility to activate bids in Finland and on Eastern Denmark, SN has similar responsibility against Western Denmark. The activating process takes approximately 10-15 minutes.

Netherlands

The balance market is based on daily bids for downward and upward regulation. The initial bids must be received by TenneT before 13.00. Bids are made for each PTU (15 min) and through the BRP of the bidder. Reserve capacity bids for upward regulation are indivisible, while reserve capacity bids for downward regulation also can be partially activated. All bids for regulation capacity can be partially activated. A bid must among others exist of the size of the up- and/or downward capacity, the price, the location in the network and the activation time. On the basis of the bids, TenneT creates the “bid-ladder” for each PTU of operation. This is equivalent to the merit order list in Figure 4-2. To obtain the desired regulation speed (MW/min), the TSO may activate several regulation bids simultaneously. The activation of a regulation bid implies the setting of a new setpoint for the unit in question.

Germany

There are separate biannual auctions for up- and downward Secondary Control capacity respectively within each balancing area. Offers include:

- One capacity price for upward regulation (€/kW)
- Two energy prices for upward regulation (€ct/kWh), for peak and off-peak periods respectively
- One capacity price for downward regulation (€/kW)
- Two energy prices for downward regulation (€ct/kWh), for peak and off-peak periods respectively

Bids are prioritized according to their capacity price in €/kW.

For Minutes reserves there are daily common web based auctions for all four TSOs [19]. Each TSO has a so-called "kernel share" of the reserves that must be obtained within its own balancing area. Auctions are daily for the next working day. For weekends and holidays they are the last working day before the actual day. Offers exist of a capacity price in €/kW and an energy price in €ct/kW).

Contracts for incremental and decremental minute reserve power are awarded separately in the four control areas. However, there are differences regarding the different tariff time bands [22]. The EnBW control area has two: Haupttarif (HT) spans Monday through Friday from 8 AM to 8 PM, and Nebentarif (NT) spans Monday through Friday from 8 PM to 8 AM and weekends and holidays from 12 AM to 12 PM. The E.ON control area has two: HT spans Monday through Friday from 6 AM to 10 PM and weekends and holidays from 8 AM to 1 PM; NT spans the other times. The RWE control area has five: 12 AM to 4 AM, 4 AM to 8 AM, 8 AM to 4 PM, 4 PM to 8 PM and 8 PM to 12 PM. The VET control area has six: RWEs largest time block from 8 AM to 4 PM is split up in two 4-hour blocks. The minimum bid size in the EnBW, RWE and VET control areas is 30 MW and in the E.ON control area 50 MW.

4.6 IMBALANCE SETTLEMENT

In general the imbalance volume in each area for each BRP is equal to their contracted energy volume compared with their metered energy volume, which can be either positive or negative. All consumption and production is metered in the grid and the difference between planned and metered generation and production is settled according to the prices established in the real time balancing.

In the following we will first discuss some general principles that form the basis for imbalance settlements.

4.6.1 Active and passive balancing

There are two types of contributions to balancing:

Active balancing: Change in production or consumption *on a request* from the TSO to activate their bid in the balance market. Active participants are mainly producers, but also consumers who can regulate their generation or consumption on request from the TSO's.

Passive balancing: Contribution to regulation *without having been requested* to do so by the TSO. Passive participants may be all parties with balance agreements with one or more TSO.

4.6.2 Imbalance pricing

There are four principles for calculation of the imbalance price:

1. **Marginal price.** The price of the last balancing unit used.
2. **Average price** of the energy balance actions.
   In Germany the average price of the activated bids for Secondary and Minute Reserves is used for settlement.
   The average price of the lowest bid for upward regulation and the highest bid for downward regulation is used in the Netherlands when no active regulation is performed**.**
3. **Pay-as-bid.** Each activation is paid the bid price.
4. **Elspot area price**
   Used in the Nordic System in case of passive balancing.

The expression "**Two price settlement**" is used when different prices are used for active and passive balancing.

Both up and down regulation can occur within the settlement period (hour, quarter) during operation. **"Single pricing**" is applied when only the price for upward regulation *or* the price for downward regulation is used and **"dual pricing"** is applied when both upward and downward prices are used within the period.

The Netherlands define an **incentive component** that is added to or subtracted from the imbalance price in the case of upward or downward regulation respectively [13]. The goal is to provide an additional incentive to the BRPs to maintain their balance. The incentive component was initially set to 10 Euro/MWh, but is presently equal to zero. It may be adjusted up by the TSO if the imbalances of significant size occur often according to defined rules.

4.6.3 Imbalance settlement period

Nordic system: 60 min
Netherlands and Germany: 15 min
Poland: 60 min

4.6.4 Regulation states

The imbalance price depends on what is called the "regulation state" and the actual balance of the BRP involved. This is a concept used by TenneT, but because of its clearness and formal character it can be used in general to describe the state of the system. The regulation state is in the Netherlands defined on the basis of the balance-delta [13]: the by TenneT operationally required contribution to the national balance maintenance from providers of control and reserve capacity. The balance delta is published by TenneT on a minute-by-minute basis. The following regulations states are defined:

Table 4-1: Regulation states [13]

Regulation state	Description
0	• neither upward nor downward regulation
+1	• only upward regulation • up- and downward regulation, and the balance-delta forms a continuous non-decreasing record
-1	• only downward regulation • up- and downward regulation, and the balance-delta forms a continuous non-increasing record
2	• up- and downward regulation, and the balance-delta forms neither a continuous non-increasing record nor a continuous non-decreasing record • up- and downward regulation, and the balance-delta is constant

4.6.5 Settlement models

Nordic System

Currently there are applied different pricing models for imbalance settlement in the Nordic countries.

Norway has chosen to use a model which comprises one-price settlement for the "total" imbalance. The total balance is calculated as the sum of actual figures both for production, consumption and trade.

In Finland the total balance is used as in Norway, but the settlement is based on the two-price model. This means that active and passive contribution to balancing is treated differently as described in the previous section.

Denmark and Sweden use two-prise settlement and three separate balances:

1. Comparison of metered production and submitted production plans
2. Comparison of submitted consumption forecast and metered consumption
3. Planned balance, calculated from submitted production plans, consumption forecast and trade

In order to harmonise the pricing principles and to pave way for a possible Nordic retail market Nordel has analysed several models [8]. Based on this work Nordel proposes that a harmonised pricing model would be based on two separate balances with the following definition:

Consumption imbalance *= Planned production + Actual trade + Metered consumption*

Production imbalance *=Metered production – Planned production*

The definition of the ***consumption imbalance*** deviates from the one used in Sweden and Denmark and comprises most of the elements in the total balance, used in Norway and Finland. The ***production imbalance*** is identical to the one used in Sweden and Denmark. ***The pricing of production imbalances would be based on two-price settlement and the pricing of consumption imbalances would be based on one-price settlement.***

In two-price settlement the regulation price is applied for imbalances in the "wrong" direction while the spot price is applied for imbalances helping the system. Two-price settlement for the production imbalance gives a stronger incentive for the producers to stick to their production plans compared to one-price settlement. This is important as the TSOs need to have reliable production plans to ensure the operational security of the power system.

One-price settlement means that an imbalance is always priced with the same price (regulation price) regardless of the direction of the individual imbalance compared to the system imbalance. The economical risk of being a BRP is lower in one-price settlement than in two price settlement. This can lower the barrier for retailers and end-users to become BRPs.
Introduction of a common model for the balance settlement will lead to a harmonised approach and cost basis for the production and consumption balance in all countries. This is important in order to create a level playing field for the market players.

Netherlands

The imbalance price in the Netherlands is given according to the rules in Table 4-2, based on the definition of regulation state in Table 4-1.

Table 4-2: Imbalance prices [9]

Regulation state	Balance price
0	• the balance price is the average of the lowest bid for upward regulation and the highest bid for downward regulation • BRPs with an unbalance with the character of withdrawal pay the balance price plus the incentive component • BRPs with an unbalance with the character of injection get paid the balance price minus the incentive component
+1	• the balance price is equal to the highest price bid for activated regulating or reserve capacity or activated emergency capacity if this has a higher price • BRPs with an unbalance with the character of withdrawal pay the balance price plus the incentive component • BRPs with an unbalance with the character of injection get paid the balance price minus the incentive component
-1	• the balance price is equal to the lowest price bid for activated regulating or reserve capacity • BRPs with an unbalance with the character of withdrawal pay the balance price plus the incentive component • BRPs with an unbalance with the character of injection get paid the balance price minus the incentive component
+2	• the balance price for upward regulation is equal to the highest price bid for activated regulating or reserve capacity • the balance price for downward regulation is equal to the lowest price bid for activated regulating or reserve capacity • BRPs with an unbalance with the character of withdrawal pay the balance price for upward regulation plus the incentive component • BRPs with an unbalance with the character of injection get paid the balance price for downward regulation minus the incentive component

The incentive component was initially set to 10 Euro/MWh, but is presently equal to zero. It is adjusted up by the TSO if the imbalances of significant size occur often according to defined rules.

With the incentive component in reality zero, we can conclude that the Netherlands use a *dual price* system based on the *total balance* with the same payment for active and passive regulation.

Germany

As for the Netherlands, prices are calculated for each 15-minutes period. Germany uses a single price system [15]. Prices are determined on the basis of the TSO's payments for Secondary Control and minutes reserves used, i.e. the *average price* is used. BRPs showing a surplus get paid the price for balancing group deviations, while BRPs showing a deficit have to pay the price for balancing group deviations. This means that in Germany the same price is received respectively paid for both active and passive regulation. The costs for the maintenance of primary and Secondary Control power and minutes reserves (the capacity payments) are part of the network tariffs.

Table 4-3 Overview imbalance settlement

	Settlement period [minutes]	Balance definition	Single/dual	BM pricing	Payment Mechanism
Norway Sweden Denmark Finland	60	Consumption (Total) + Production	Dual (all countries from 2009)	Two prices	Marginal price
Netherlands	15	Total	Dual	One price	Marginal price
Germany	15	Total	Single	Two prices*	Pay as bid / Average price

* In a different sense than in the Nordic countries, see text.

5 PRESENT POWER EXCHANGE BETWEEN THE NORDIC AND THE UCTE SYNCHRONOUS SYSTEMS

The content in this chapter is mostly collected from [2]. The present practice with regard to the exchange of reserves between the synchronous Nordic System and Western Denmark, which is performed within the Nordel cooperation, is included in the description as an example of exchange between synchronous systems.

5.1 NORWAY / SWEDEN – WESTERN DENMARK

The joint list of regulation bids contains bids from both the synchronous system and Western Denmark. During the hour of operation, regulation is initially carried out for network reasons and then, if necessary, to maintain the frequency in the synchronous system or the balance in Western Denmark. Regulation carried out for network reasons need only be in one direction.

Power exchange between the synchronous system and Western Denmark primarily takes place in the form of supportive power[7]. For the regulation of the frequency of the synchronous system and the balance in Western Denmark, the bids on the joint regulation list are used in the order of price, with the exception of bids confined behind a bottleneck. The activated bids are marked as balance regulations and are included when calculating the regulation price and regulation volume.

Exchange of supportive power for balance regulation between the synchronous system and Western Denmark is carried out in accordance with a set model based on the below principles.

Energinet.dk sends plans in advance for each operating hour for exchange between the synchronous system and Western Denmark. The plans are given per 15 minutes and they are drawn up on the basis of forecasts for imbalance in Western Denmark, current bids in the joint regulation list and other information exchange between Statnett and Energinet.dk.

Statnett and Energinet.dk are jointly responsible for the plan concerning the coming hour being acceptable with respect to regulation in both systems at the latest 15 minutes before the hour shift.

After this, the plan can be altered during the hour of operation in accordance with the rules below.

Supportive power is exchanged between the synchronous system and Western Denmark in one direction only during each hour. The volume can increase or decrease during the hour of operation, but not more often than every 15 minutes.

After a decrease in the supportive power volume, the volume cannot increase again during the same hour. However, this does not apply to hour shifts if the agreed exchange during the coming hour is higher than the current volume.

[7] Supportive power is defined as: Power that adjacent TSOs can exchange as an element of the regulation of balance in respective subsystems.

Exchange of supportive power takes place in accordance with a power plan at 5 minutes' discontinuation. In the activation of supportive power during the hour of operation, a change in the power

The following applies to pricing of supportive power for balance regulation between the synchronous system and Western Denmark:

When the balance in the synchronous system and Western Denmark is regulated in the same direction, the price of supportive power is set to that regulation price – if they are different – which is closest to the system price in Elspot. The same rule applies when there is no regulation in any of the areas.

When the balance in the synchronous system and Western Denmark is regulated in different directions, the price of supportive power is set to the system price in Elspot.
In the event of bottleneck situations, it may be appropriate to carry out triangular supportive power exchanges between Sweden, Norway and Western Denmark. This will not affect the individual subsystem's balance and the price of the exchange will be set at 0 SEK. Supportive power for balance regulation has priority over triangular transit.

5.2 WESTERN DENMARK – GERMANY

Since the middle of the 1960's, Western Denmark has been parallel-connected with the German high-voltage network and has thus been a part of the synchronous continental UCTE system. Energinet.dk has been a part of E.ON Netz' balance area, thus meeting the formal UCTE requirements. Irrespective of this, Energinet.dk shall comply with all the requirements set by UCTE. Energinet.dk is formally an associated member of UCTE.

Energinet.dk is connected to E.ON Netz via the following links:

- 220 kV Kassø – Flensborg, settlement point Kassø
- 220 kV Ensted – Flensborg, settlement point Ensted
- 2 st 400 kV Kassø – Audorf, settlement point Kassø.

The transmission capacity is normally 1,200 MW in both directions. Taking into account faults at major production facilities, the transmission capacity northbound is 800 MW, in relation to planning.

Energinet.dk and E.ON Netz are discussing a system operation agreement. Irrespective of this agreement, Energinet.dk must comply with the following UCTE requirements:

- Contribute to the combined momentary reserve of the synchronous continental system. The proportion is determined by the dimensioning faults, and the requirement in relation to the system operator's production in his own area. See ch 3.4.
- The network-regulating function on the Danish-German border
- Each area inside UCTE must be able to manage its own balance
- Trading plans are specified in quarter-hourly and hourly energy

- The energy plan is converted to a power plan. To include the energy as per the trading plan, regulation is commenced between five minutes before and five minutes after an hour shift

The ramping requirement for exchanges with E.ON Netz has a direct impact on transiting between the synchronous system and the continent. This means that the five-minute requirement is directly transferred to the transiting, when changes are made in the same direction during hour shifts.
The transmission capacity across the Danish-German border is utilized for commercial purposes in accordance with the following principles; a detailed description can be found on the Energinet.dk and E.ON Netz websites.

- Annually and monthly, some of the transmission capacity in each direction is offered at auction. The winners of the auction obtain the right to submit bilateral trading plans via the Danish-German border on the morning prior to the day of operation. These plans are binding. Unutilized capacity is lost.
- Every day, the remaining part of the transmission capacity in each direction is offered at auction. The winners of the auction obtain the right to submit bilateral trading plans via the Danish-German border on the day before the day of operation. Utilization of the capacity is not compulsory.

There are formal requirements for the traders to comply with in order to be able to take part in the auction.

5.3 EASTERN DENMARK – GERMANY (KONTEK)

The Kontek goes between Bjaeverskov on the Danish side and Bentwisch on the German side. Energinet.dk is the owner of the facilities in Denmark and the cable link across to the German coast. Vattenfall Europe Transmission is the owner of the facilities in Germany. The link is connected to the 400 kV network in Zealand and Germany. The transmission capacity is 600 MW.

The link’s transmission capacity is utilized as follows:

- Southbound:
  550 MW is made available to Nord Pool Spot for Elspot trading.
  50 MW is utilized for the frequency controlled disturbance reserve.
- Northbound:
  550 MW is made available to Nord Pool Spot for Elspot trading.
  50 MW is utilized for the frequency controlled disturbance reserve.
- Settlement point: Bentwisch.

5.4 SWEDEN – GERMANY (BALTIC CABLE)

The Baltic Cable goes between Trelleborg on the Swedish side and Lübeck on the German side. Baltic Cable AB owns the cable link. The capacity is 600 MW.

The link is used today for Elspot trading. The utilization fees are regulated by means of a tariff. Idle capacity permits the TSO Svenska Kraftnät to do supportive power deals via E.ON Sverige.

5.5 SWEDEN – POLAND (SwePol)

The SwePol HVDC link goes between Karlshamn on the Swedish side and Slupsk on the Polish side. SwePol Link AB (Svenska Kraftnät, Vattenfall AB,Polish Power Grid Company (PPGC)) owns the cable link. The capacity is 600 MW. The link is controlled half-yearly from the respective system operators SvK and Polskie Sieci Elektroenergetyczne (PSE).

The system operation collaboration is regulated by a system operation agreement. This agreement regulates Technical limitations, Outage co-ordination, Emergency power functions, Exchanges of trading plans etc.

SwePol Link AB is a transmission company that sells transmission capacity on the link. Today, the bulk of the link's capacity is being utilized via a long-term agreement. A minor part of the capacity remains unutilized. Idle capacity permits the TSO to do supportive power deals.

6 POTENTIAL MARKET MODELS FOR EXCHANGE OF RESERVES BETWEEN SEPARATE SYNCHRONOUS SYSTEMS

The intention of this chapter is not to present solutions for these issues – rather to present a basis for further discussion and research within the project.

We can define three levels of ambition for the exchange of reserves (in assumed order of feasibility):

1. HVDC terminal acts as a source for manual secondary control providing FRR (tertiary reserve in UCTE) and acts as a deductible (upward regulation) or increasable (downward regulation) load on the side that procures the reserve.

2. HVDC terminal acts under AGC and contributes to the automatic secondary control referred to the local ACE

3. HVDC terminal contributes to the Primary Control

It is implicitly assumed that the exchange of manual FRR can be both ways, but that the potential automatic primary and/or secondary control will provide reserves only from the Nordic system to the UCTE system. The reason for this is the advantageous controllability of the hydro dominated Nordic system

A prerequisite for an efficient market is that the flow direction in normal operation should be from the low priced to the high priced areas. Unless a certain capacity is set aside for reserve purposes, this means that the exchange of reserves depends on the spot market power flow. In a situation of maximum import over the HVDC connection, only downward regulation can be provided to the importing country. Similarly, in a situation of maximum export, only upward regulation (in the form of reduced delivery to the terminal) can be provided. This is, however, not fundamentally different from the situation in the Nordic reserves market today: there is one integrated market, but the actual activation of reserves depends on the transmission constraints.

6.1 MANUALLY ACTIVATED RESERVES

The exchange of manually activated reserves seems to be the easiest starting point, and an integrated market of manual reserves could be a future option. The regulation objects in the Nordic system are available for the TSOs in the common merit order list. The use of these resources in this context should in principle be equal to the present utilization practice between the Nordic synchronous system and Western Denmark.

It is not clear whether the tertiary reserve on the continent could be traded over the borders e.g. between the 4 German TSOs and TenneT. If not, each HVDC connection should have a separate arrangement. The pricing and settlement mechanisms would in any case be the tricky point due to the different ways of reserve utilisation.

6.2 AUTOMATICALLY ACTIVATED RESERVES

For the sake of the discussion of the automatic primary and secondary control we concentrate on the exchange between Norway and the Netherlands over NorNed.

All the UCTE control regions connected to the Nordic system have AGC and ACE based Secondary Control. This is probably the most important difference that has to be taken into consideration when models for BM trade are developed. It is assumed that if Norwegian hydro power would take part in the Dutch Secondary Control, it is necessary in some way to extend the use of TenneT's AGC to parts of the Norwegian system. At this preliminary phase, we see three potential models:

1. The AGC controls the HVDC terminal only
2. The AGC controls the HVDC terminal *and* Norwegian generators
3. Integrated balance market

In the following we assume that the Norwegian market offers secondary reserves in the Dutch system.

6.2.1 AGC controls the HVDC terminal only

Technically this should not be a major challenge. However, there are considerable challenges from a market point of view. To mention some:

- The AGC uses the bid ladder (cf. Section 3.9.2 and 8.2.2) to determine the next object to regulate; how should the HVDC be priced? It is controlled by the TSO, but the TSO has no regulation resources of its own.
- If the TSO could use the Nordic balance market as a resource, how should it be priced? The price is not known until the end of the hour.
- How should the regulation of the HVDC line be coordinated with the Secondary Control in the Norwegian system? The response will be picked up by the Nordic system and the droop based Primary Control, and the need for Secondary Control actions needed depends on the behaviour of the rest of the system. In other words, this will not necessarily lead to activation of Nordic balancing power.
- The Dutch system uses 15-minutes settlement, the Norwegian system hourly settlement.

6.2.2 AGC controls the HVDC terminal and Norwegian generators

In this case we assume that Norwegian generators bid directly into the Dutch market. The AGC controls both the HVDC terminal and simultaneously one or several generators. This is technically more challenging, but should be feasible today. However, there are challenges:

- How should generators divide their bids between the Dutch and Norwegian markets?
- Is it efficient to divide resources between two separated markets?
- How will AGC actions affect the Nordic system balance and stability?
- The Dutch system uses 15-minutes settlement, the Norwegian system hourly settlement.
- How large share of the Dutch reserves can be located outside the Dutch balancing region?

6.2.3 Integrated balancing markets

Some of the issues in the previous Section could be solved through an integrated balance market, similar to the present Nordic balance market. Naturally this would imply a number of other challenges.
In principle one can imagine that all producers in Northern Europe offer their balancing capacity to one single balancing market. The TSOs would then use the common "bid ladder" to find the cheapest object for upward or downward regulation, based on frequency deviations – i.e. exchange between balancing areas would not or only to a limited extend be taken into account. One obvious challenge would be how to handle the HVDC interconnections. Another obvious challenge is the fact that the UCTE system uses AGC, while the Nordic system uses manual control. One can see two possible solutions for this:

a. The Nordic system implements AGC
b. The UCTE system accepts a combination of AGC and manual control

The second option would violate present UCTE requirements, cf. [3] R3: "In order to control the ACE to zero, secondary control must be performed in the corresponding control centre by a single automatic Secondary controller, that needs to be operated in an on-line and closed-loop manner."

It should be noted that both the Netherlands and Germany today use manual controlled Reserve Capacity and Minutes Reserves respectively in combination with AGC. However, both are used rather sporadically, and are basically viewed as tertiary reserves. In the Netherlands the Reserve Capacity is primarily used to handle bottlenecks. These reserves have normally lower regulation speed, which in any case often makes them less attractive. Hydro power units on the other hand have a higher regulation speed, and could be more attractive and cheaper to regulate. In this case it is an obvious challenge to determine how to combine manual control with AGC – if this is feasible at all.
In any case full integration of the balance markets is an extremely ambitious target.

6.3 DROOP BASED PRIMARY CONTROL

The technical challenges with regard to the exchange of primary reserves via the HVDC connection are fundamental, but not impossible to solve. According to Appendix C all control aspects with regard to droop based control of the power flow of the HVDC terminal as such are feasible, but not necessarily in place in the NorNed terminals. The challenges are therefore mainly related to the operational and commercial impacts of the interconnection between the two separate synchronous systems.

7 CONCLUSIONS – FURTHER WORK

Well functioning balancing services reflect technical requirements for safe operation of the power system. Combination with market mechanisms and harmonisation between the different sub systems is a demanding challenge, involving both the central and local control of the balancing resources and the pricing and settlement arrangements.

This report gives an overview of the main aspects regarding the primary and secondary control of the separate synchronous Nordic system and the UCTE system. The use of terminology varies from region to region, reflecting the different properties and history inherited in the different parts of the power system. The main terms are therefore defined in the report in order to provide a common understanding. The definitions used are mostly identical to the one used by ETSO.

There is an ongoing process towards a common Day Ahead market in Europe through market coupling between the separate markets. The Nordic market will according to plans be coupled to the Central Western European market within the end of 2009. The TSOs will, in parallel to this, work for harmonisation of the balancing mechanisms. This is especially on the agenda for the two TSOs directly involved in this project, Statnett and TenneT, as a part of the NorNed cooperation.

The main objective for this project is, besides building of competence, to contribute to the design of an efficient market based balancing scheme that will improve the utilisation of the balancing resources and reduce the costs. This report and the report from WP 2 "Documentation and analyses of present costs" form the basis for further work. It is the intention that this work will be supplementary to ongoing efforts in the industry and bring new aspects for the project stakeholders.

The project will in the following focus on both technical aspects, regarding control of regulation objects and HVDC links, and market issues. The following topics will be prioritized:

I. Exchange of "manually" activated reserves.
II. Control schemes based on Automatic Generation Control (AGC) across HVDC links.
III. Integrated balancing markets with focus on the connection and interplay between the day ahead, intraday and balancing markets, and the impacts on the real available balancing resources in the hour of operation.

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APPENDIX A: ACRONYMS AND ABBREVIATIONS

ACE	Area Control Error (control criterion in the UCTE system)
AGC	Automatic Generation Control
APX	Amsterdam Power Exchange
Belpex	Belgium Power Exchange
BM	Balance Management
BRP	Balance Responsible Party
CENTREL	Balancing region covering Czech Republic, Hungary and Slovakia
CWE	Central Western European
EEX	European Energy Exchange
ELBAS	Nordic intraday market operated by Nord Pool
ETSO	European Transmission System Operators
FADR	Fast Active Disturbance Reserve (Nordel)
FCNOR	Frequency Controlled Normal Operating Reserve (Nordel)
FCR	Frequency Containment Reserve (Nordel)
FRR	Frequency Restoration Reserve (Nordel)
HVDC	High Voltage Direct Current
IEM	Internal Electricity Market
IET	"Import – Eksport – Transit" (TenneT)
LFC	Load Frequency Control
MOU	Memorandum of Understanding
NCC	National Control Centre
PTU (PTE)	Program Time Unit = 15 minutes (Dutch: PTE)
RES	Renewable Energy Systems
RKOM	Regulation Option Market (Norway)
RPM	Regulation Power Market
SvK	Svenska Kraftnät
TEN	Trans European Networks
TLC	Trilateral Market Coupling (NL+ B + F)
TSO	Transmission System Operator
UCTE	Union for the Co-Ordination of Transmission of Electricity (in Europe)

APPENDIX B: TECHNICAL BACKGROUND PRIMARY AND SECONDARY CONTROL

B.1 PRIMARY CONTROL

Load and production will vary all the time in normal operation. This will lead to positive and negative imbalances, and corresponding changes in frequency, that must be taken care of in order to maintain a stable system operation. All of the units that are contributing to the primary control will, within a few seconds, react to a sudden deviation in frequency with a change in output. According to physics will loss of production (or sudden increase in load) result in an instant drop in frequency, and the inertia in the system will help to maintain the physical balance between production and consumption. This drop in frequency initiates the automatic up regulation in the power stations contributing to the Primary Control.

The units involved are required to reserve a small amount of the nominal power for the Primary Control as a part of the total FCR for the system. Note that the FCR also is supported by the passive share of frequency dependent load. This “self-regulation effect” counts for about 1 % of the total load in case of a frequency drop of 1 Hz.

The Frequency Response (R [MW/Hz]) from the different generators is decided by the droop setting, δ, of the respective governor and adds up to the total R for the synchronous system, which decides the stationary frequency deviation Δf. The response time is from 3- 30 seconds and will in case of stationary imbalance lead to a frequency deviation Δf and an additional activated production ΔP as seen in Figure B-1.

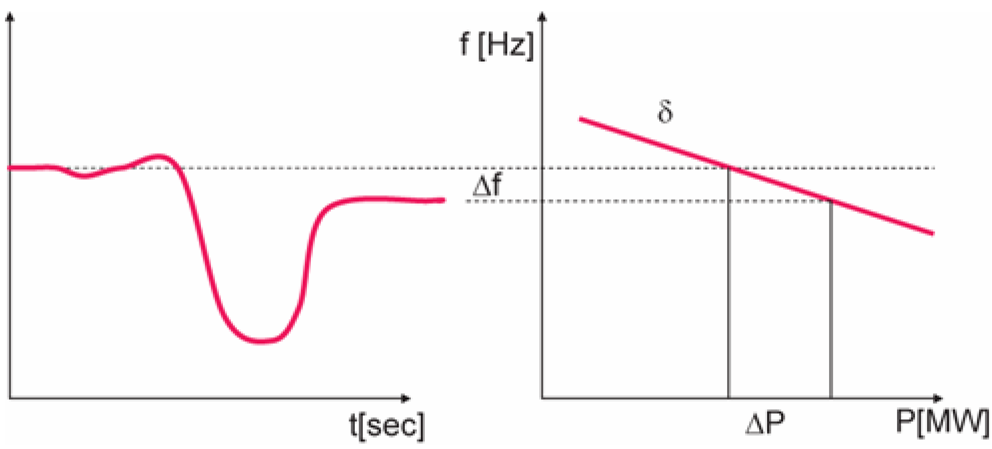

Figure B-1 Frequency response from Primary Control

For the total system the **ΔP** is the **FCR** activated by Primary Control. This is in this report (Ch. 2.1) defined as the “*instantaneous imbalance*” that has to be compensated by activation of the FRR by secondary control.

B.2 SECONDARY CONTROL

The Secondary Control is, as defined in Ch. 2.2, the activation of FRR by change of the set point (MW) of the balancing resources (regulation objects).

The Secondary Control is initiated by the TSO on specific criteria referring to frequency (Δf) and time (Δt) deviation or the Area Control Error (ACE).

The ACE, which implies that each balancing area shall maintain its balance, is the main control criteria for Secondary Control in the UCTE system. This used to be the case also in the Nordic system, but from in 2001 Nordel decided to remove this criterion and only refer to Δf / Δt and the potential congestions in the transmission system.

The balancing resources (FRR) can either be activated "manually" by phone or message from the national control centre to the local control centres or by automatic schemes. Only manual secondary control is used in the Nordic system, while most of the secondary control in the UCTE is automated as part of the centralized Automatic Generation Control (AGC). Generally the automatic Secondary Control is faster than the manual, which is needed in a complex system with balance responsibility distributed among many TSOs.

The basic principles of the manual and automatic secondary control are described in the next sections followed by a description of how the secondary control in the Netherlands works.

B.2.1 Manual Secondary Control (Nordic system)

The four Nordic TSOs coordinates the secondary control according to the common System Operation Agreement [2]. The control criteria are frequency deviation Δf and time deviation Δt in the Nordic synchronous system.

The TSOs uses the common merit order list of regulation objects for up and down control which includes objects from the whole Nordic system sorted by price independent of location. The resources available are prioritized according to the bids in the Regulation Power Market (RPM). The respective TSO in the country having the next object on the list will, when secondary control is needed, phones the local control centre of the Balance Responsible Party (BRP). The BRP is responsible for activation of the specific resource within 15 minutes.

B.2.2 Automatic Secondary Control

The main control criterion for the automatic secondary control is the ACE, which represents the total power deviation of a system (MW) and comprises unscheduled power exchanges of the area with neighbouring areas and the frequency deviation of the system:

$ACE = \Delta P_{exc} + R\Delta f$

ΔP_{exc} = the deviation from planned exchange between balancing areas
R= Frequency Response (MW/Hz) in the specific area

The functionality of the automatic secondary control is illustrated by the following example.

Example

The basic principles of ACE control (more commonly referred to as *Load-Frequency Control LFC*), can be illustrated with a simplified example where two separate system areas are exchanging power across a single inter-area tieline. After a sudden loss of generation capacity in area 1, the system frequency drops and all synchronized units react to the fault with an increase in their production to stabilize the frequency at a new level, regardless of which area they belong to. Thus, initial export from area 1 to area 2 is reduced.

If the frequency dependency of all components in the system is known or measured, the area *frequency response* R_i can be established for each interconnected area:

$$\frac{\Delta P}{\Delta f} = -\mathrm{R}_i \quad \text{(MW/Hz)}$$

Following a loss of generation ΔP_f the stationary frequency deviation of the interconnected system is given as:

$$\Delta f = -\frac{\Delta P_f}{R_1 + R_2} \quad \text{(Hz)}$$

where R_1 = Frequency response of Area 1 (MW/Hz)
R_2 = Frequency response of Area 2 (MW/Hz)

To establish the new operating situation, Area 1 has activated Primary Control reserves of $\Delta P_1 = -R_1 \cdot \Delta f$, while area 2 is assisting area 1 by delivering $\Delta P_2 = -R_2 \cdot \Delta f$ of its primary reserves in the form of a reduced import. Thus, $\Delta P_{exc} = -\Delta P_2$. The Area Control Error (ACE) for each area can now be defined as:

$$ACE_i = \Delta P_{exc,i} + B_i \cdot \Delta f \quad \text{(MW)}$$

where $\Delta P_{exc,,i}$ = Net area interchange deviation (MW)
B_i = Frequency bias setting (MW/Hz)
Δf = System frequency deviation (Hz)

In the ideal case, $R_i = B_i$ and the resulting ACE for the two areas are:

Area 1: $ACE_1 = \Delta P_{exc} + B_1 \cdot \Delta f$
$$= R_2 \cdot \Delta f + R_1 \cdot \Delta f$$
$$= (R_2 + R_1) \cdot \Delta f = -\Delta P_f$$

Area 2: $ACE_2 = -\Delta P_{exc} + B_2 \cdot \Delta f$
$$= -R_2 \cdot \Delta f + R_2 \cdot \Delta f = 0$$

The Area Control Error for the faulted Area 1 is equal to the size of the fault, while the ACE for the faultless Area 2 is zero. Thus, the ACE is a direct indicator of the location of the fault. This also the case in multi-area interconnected systems. Figure B-2 shows the trajectory of ACE vs. frequency in a case where only Primary Control is activated.

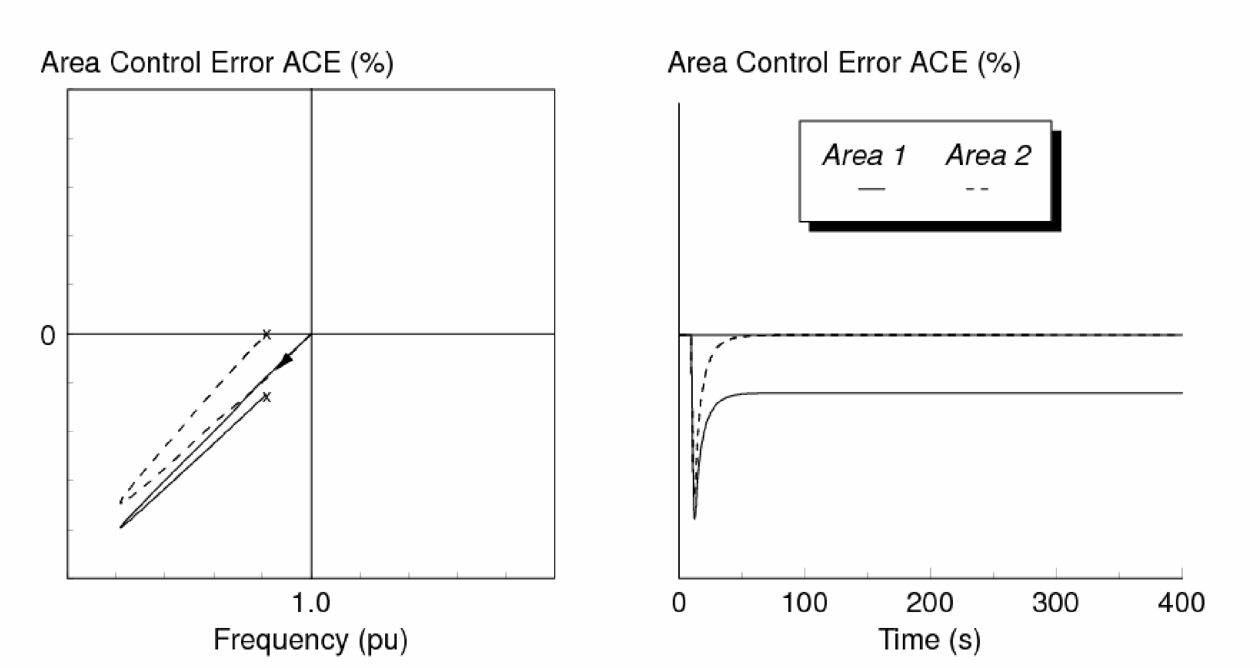

Figure B-2 Area Control error due to Primary Control [26]

Closed-loop Secondary Control, or *Load-Frequency Control (LFC)*, is introduced by integrating the ACE and sending a signal for additional output to the set point of selected generation units. Different controller designs are used in different areas in Europe and in other synchronous systems around the world, but the main principle remains the same: Using ACE as an indicator for the location of the fault, generators in the responsible area increase their output to balance the system, while the other areas that supported the frequency with primary response capacity after the fault can return their units to scheduled output again, and system frequency and interchanges return to scheduled values. See Figure B-3.

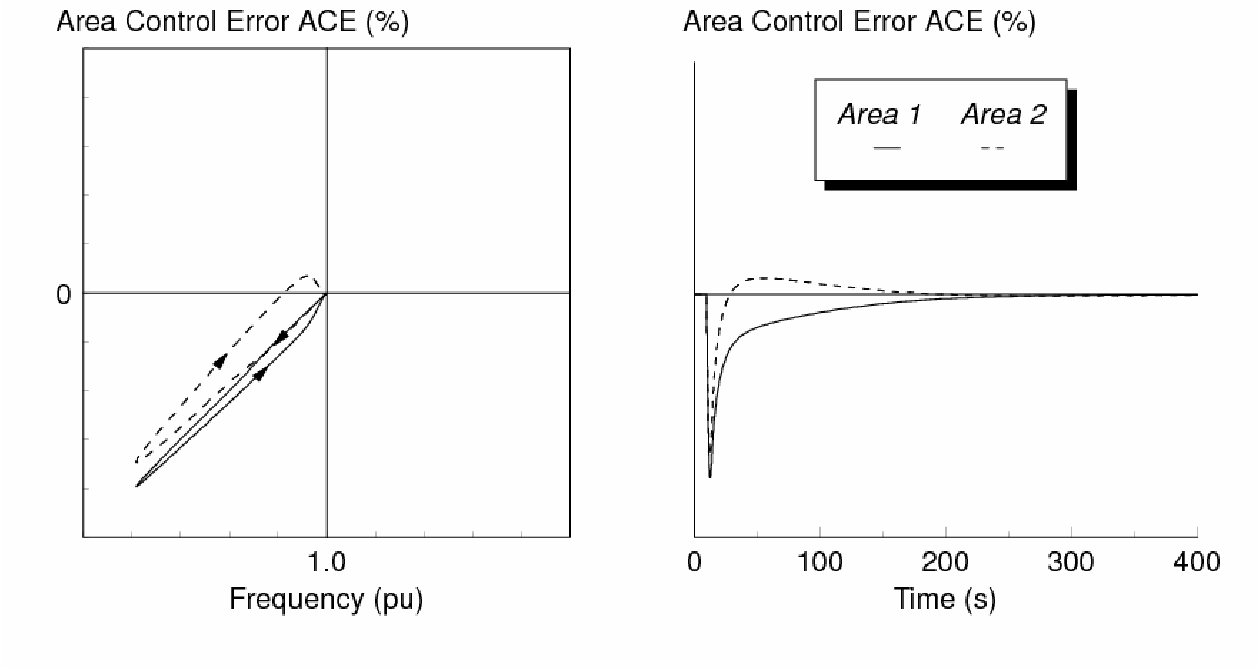

Figure B-3 Area Control Error with Load-Frequency Control [26]

The slow integrating control function of the LFC is quite stable and robust, and will bring the interconnected system back to scheduled values no matter where the fault happens. Different controller designs and different parameter settings may cause more or less oscillations but the system will eventually come back to the steady state, even though the frequency bias setting B_i in each controller is not exactly equal to the real area frequency response R_i .

B.2.3 Automatic Secondary Control in the Netherlands

For Secondary Control purposes ACE is typically processed by the National Control Centre using a PI-controller (ACE and Processed ACE (PACE)) before it is sent to units on Secondary Control [14]. The PACE-logic has the objective of minimizing ACE while neglecting fast dynamics in system frequency, which would result in unnecessary, fast changes in demands for Secondary Control.

For real-time power system balancing, the TSO applies secondary reserves made available by the BRPs through a bidding ladder (selection of cheapest bids). Bids are orderly arranged based on price in a power reserve bidding ladder, a separate ladder for upward and downward reserves. During real-time operation, the TSO continuously determines the amount of reserve power that is needed, based on the actual PACE. Using the bidding ladder, the amount of required reserves is mirrored onto the available bids which are then called off by the TSO. This is done by sending a delta-signal (MW-set point) to the BRP associated with each bid called, using a separate delta for both upward and downward reserves. The rate-of-change of delta does not exceed a ramp rate value pre-specified by the associated BRP. Every four seconds, the PACE is re-calculated to determine whether the sum of all bids called (MW) is sufficient for balancing the balancing area and which bid should be used up to which extent. In case PACE drops below an active bid's threshold and the bid is no longer necessary, the bid is reduced with a ramp rate no more than the maximum specified in the bid. Because of this ramp rate limitation, positive and negative bids may be active simultaneously. It is the responsibility of the market party associated with the bid called off to adjust its generation operating points and/or load schedules accordingly.

When a power imbalance is picked up by the TSO (i.e. ACE) and secondary control is activated, the generation/load deviations from scheduled values causing it will also be picked up by the BRP responsible for it. Simultaneously with secondary control at the system level, the BRP will take measures in order to minimize its energy program deviation (not necessarily its power imbalance) in order to avoid imbalance costs. The BRP will not only monitor its power imbalance (MW), but also physical position (MWh) within the given Program Time Unit (PTU) which for the Netherlands is 15 minutes. The actual power imbalance of each BRP is constantly assessed by monitoring generation and load deviations from scheduled values while settling the secondary control signal received from the TSO. For imbalance minimization, a fraction of the actual power imbalance is integrated and subtracted from the set-point of generation units selected by the BRP for imbalance management. Because participation in secondary control is taken into account in calculating its imbalance, both the BRPs' imbalance and the system imbalance are eventually returned to zero as illustrated in the example in the previous Section.

Since imbalance costs are settled not on a MW but on an MWh/PTU basis, the energy imbalance for each PTU is the most relevant parameter for a BRP. The MWh-value specified in the BRPs' energy program is the operational objective: during each PTU, the overall energy deficit or surplus compared to the energy program must be minimized. For the counter-balancing of power deviations, different operating strategies for imbalance minimization may be applied in order to reach the energy value objective. At the start of each PTU, the energy-program deviation is reset to zero.

APPENDIX C: EXCHANGE OF BALANCING SERVICES VIA HVDC LINKS. TECHNICAL POTENTIAL AND LIMITATIONS

C.1 HIGH VOLTAGE DIRECT CURRENT (HVDC) TRANSMISSION

High Voltage Direct Current (HVDC) transmission is a quite common technology today to connect two synchronous power systems and to transmit large amounts of energy over large distances. The following are the most common applications of HVDC technology:

- In competition with traditional AC technology
  - transmission of large amounts of energy over large distances
  - system stabilization and damping of oscillations
  - limited construction space and/or request for underground cables
  - special requirements for control of power flow

- Without competition from AC technology
  - interconnection of two synchronous areas with different nominal frequency and/or frequency control principles
  - long distance sub sea transmission

The most common layout of HVDC connections today is the bipolar design of Figure C-1. In normal operation, the current is flowing back and forth through the two interconnectors and no return current is flowing uncontrolled in earth or sea. During revisions or outages, however, each single pole can be operated separately with temporary return current in earth or sea.

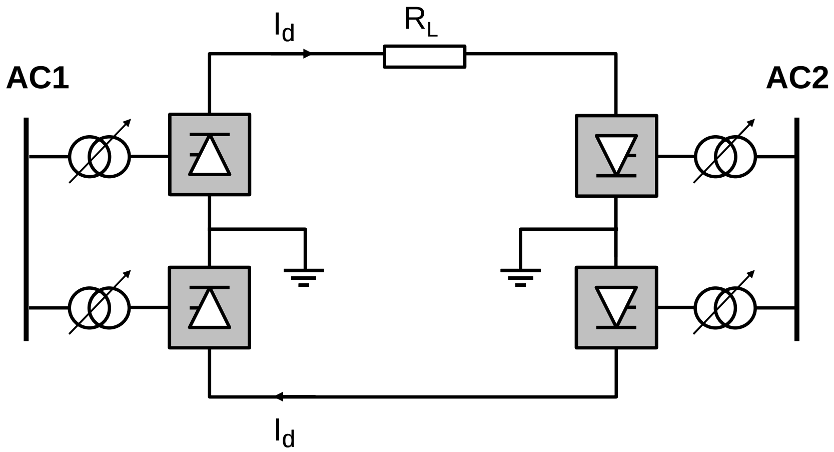

Figure C-1 Bipolar HVDC connection

The DC converters in high-capacity HVDC systems are still based on thyristor technology, but modern transistor (IGBT) based solutions are constantly improving their rating. The HVDC-Light concept of ABB is one example. In general, transistor based HVDC systems are more controllable than thyristor based systems, enabling full control of both active and reactive power, but these are not yet competitive in the capacity range of the NorNed connection (700 MW). Common problems related to operation of thyristor based HVDC systems are the following [27][28]:

- High reactive power demand in both rectifier and inverter
- Sensitive to commutating errors at low AC voltage
    - one valve does not switch off before the next ignites
- Frequency deviations
    - if the AC-system has low inertia compared to the rating of the HVDC connection, fast changes in HVDC transmission can affect the system frequency
- Risk of temporary overvoltages
    - if the HVDC transmission has an outage, both active and reactive power goes to zero in a few milliseconds. If the short circuit ratio of the AC system is low this instantaneous loss of power may cause large overvoltages.
- Problems with overharmonic currents and voltages
    - all converters generate overharmonic currents and voltages both on the AC and the DC side
    - may cause extra losses and heating of generators and capacitors, instable control and EM disturbances
    - these overharmonics may be transmitted over large distances
    - compensated by installing tuned filters at the terminals
- Harmonic resonance between converter/filter and surrounding AC system
    - may occur under unfavourable conditions down to 4th, 3rd or 2nd harmonic
- Voltage flicker
    - reactive power demand of converters is proportional to HVDC transmission, while capacitor banks are regulated in discrete steps. This mismatch might cause voltage flicker, especially in weak AC networks.
- Voltage instabilitiy
    - ordering increased DC current might cause reduced AC voltage, preventing the desired increase in transmitted power.
    - if the connection is operating in constant power mode, the converter will try to increase the current further to reach scheduled power, increasing also reactive power demand
    - might trigger a voltage breakdown, especially in weak AC networks

C.2 BASIC CONTROL PRINCIPLES OF HVDC TRANSMISSION

A simplified single line diagram of an HVDC connection is shown in Figure C-2. The current flow is mono-directional given by the thyristors, while the terminal voltages change polarity to change direction of power flow. As the resistance of the transmission is approximately constant, the DC current is a function of the voltage difference between the two terminals. The transmitted power is given as the product of DC current times DC voltage.

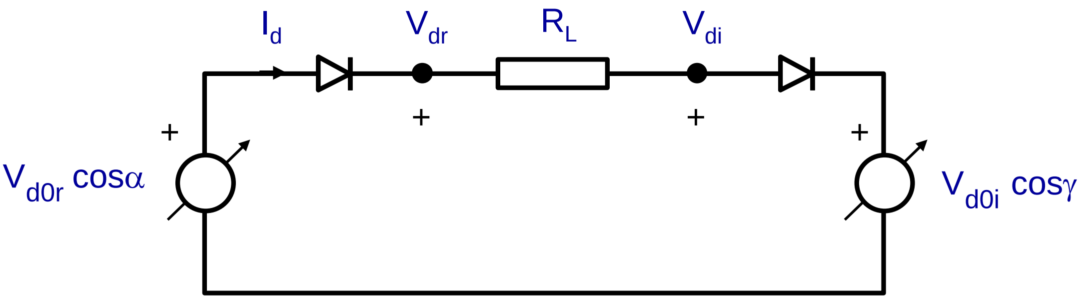

Figure C-2 Simplified single-line equivalent of HVDC connection

The control system for an HVDC connection is quite complex, but the main principle can be explained as shown in Figure C-3: The rectifier operates in "Constant Current" (CC) control mode to control the DC current while the inverter operates in "Constant Extinction Angle" (CEA) mode to control the DC voltage. The main elements of the control system are shown in Figure C-4. The operating point P_{ref} is given to the HVDC connection from operator or day-ahead schedule. If the direction of power flow is reversed, the rectifier and the inverter change roles.

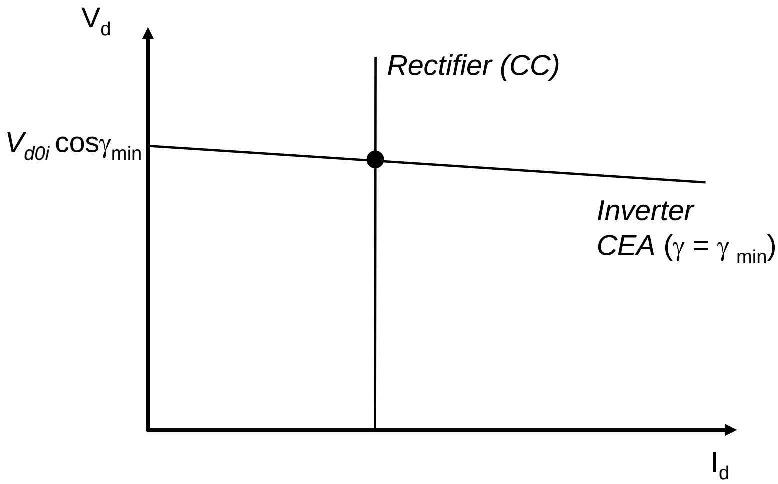

Figure C-3 Basic control principle of HVDC connection

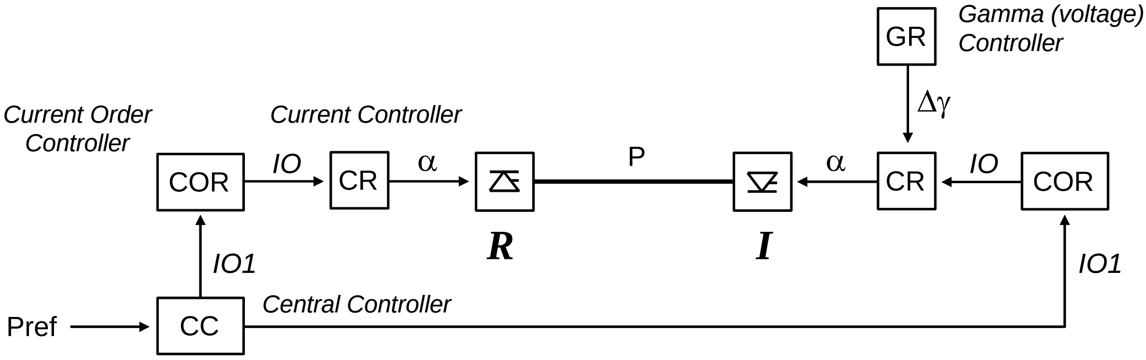

Figure C-4 Main functions of HVDC control system

C.3 PRIMARY CONTROL (DROOP)

To enable the HVDC connection to participate in control actions other than following the schedule given by P_{ref} an additional current order signal Δi_{DC} can be added to the central controller as shown in Figure C-5.

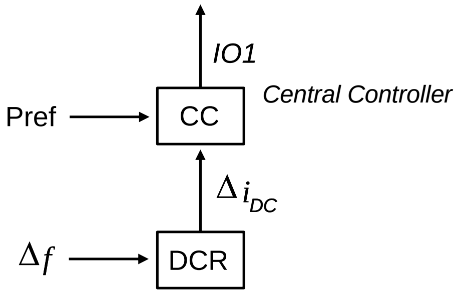

Figure C-5 Additional (delta) current order signal to central controller

The additional current order signal can in principle be based on a number of different inputs. In this case, we use system frequency measured at the HVDC terminal multiplied with a constant gain k_{DC} to obtain a "droop" control behaviour of the connection around the set point P_{ref} similar to the droop control of a generating unit:

$$\Delta i_{DC} = -\frac{k_{DC}}{I_{DN}} \cdot \Delta f \quad \text{(pu)}$$

The controllability of the HVDC connection is faster than any mechanical generation unit in the system, even for large load changes, so the limiting factor is normally the strength and stability of the surrounding networks. The main exception is if the control action should cause a change in power flow direction. In that case, the polarity of the cable has to change; decharging and recharging the capacitance of the connection before providing the necessary reserve. This situation can be avoided with proper controller design.

A subsea cable is heated by the current from the inside and cooled by the sea from the outside. During repeated cycles of heating and cooling this might cause stresses and fractures in the cable insulation, especially in oil-paper insulated cables. An HVDC connection has a certain overload capacity that can be used within the time frame of both primary and secondary reserves, so the thermal cycling might be a larger problem than the steady state capacity. This should be referred to the technical documentation of the respective connection.

The following figures are taken from [26] and show computer simulations where data from the 500 MW Skagerak 3 HVDC connection is used to represent an HVDC link between two highly simplified "Nordic" and "German" power system models. They are included here to illustrate basic principles, and cannot numerically be transferred to the current NorNed connection.

Figure C-6 compares primary response of HVDC connection to typical hydro (H_SW. H_500) and thermal (T_SW) units following a 250 MW outage in the receiving (thermal) system. The HVDC connection initially operates at 50% rated load, and supports the Primary Control with nearly 40% capacity within a few seconds. This is much faster than any mechanical unit can respond, and the drop in system frequency is therefore arrested much quicker, as shown in Figure C-7. Due to the HVDC load change the sending (hydro) system will experience a larger transient frequency deviation as the hydro power units respond slower the first seconds after the outage.

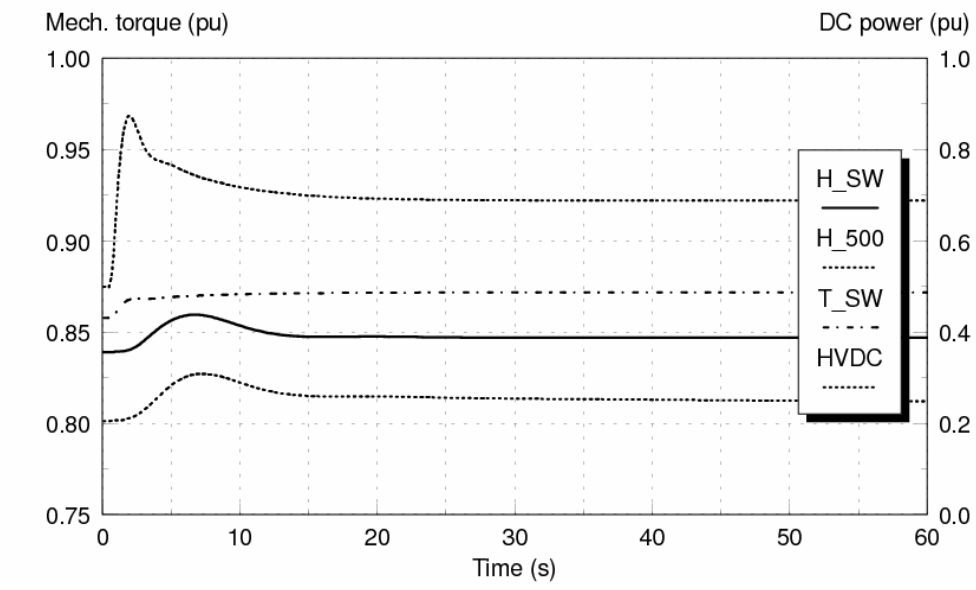

Figure C-6 HVDC power transfer compared to mechanical torque of Hydro (H_SW, H_500) and Thermal (T_SW) power units after loss of 250 MW capacity in thermal system [26]

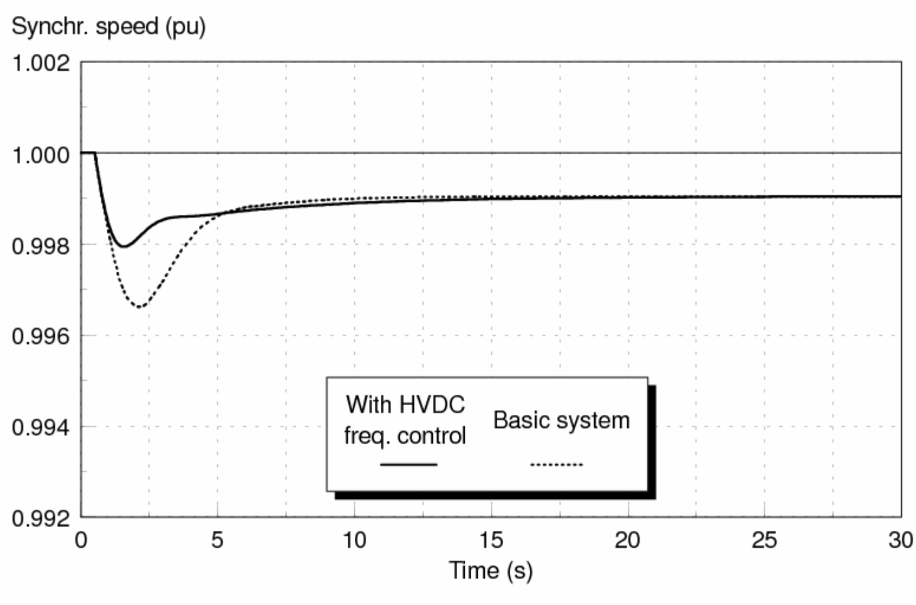

Figure C-7 Improvement of frequency deviation in receiving (thermal) system after loss of 250 MW capacity with Primary Control on HVDC connection [26]

If the outage is large enough compared to the available capacity of the HVDC connection, the frequency response will drive the connection into saturation as shown in Figure C-8. This situation is handled by the overload control already implemented in the HVDC control system.

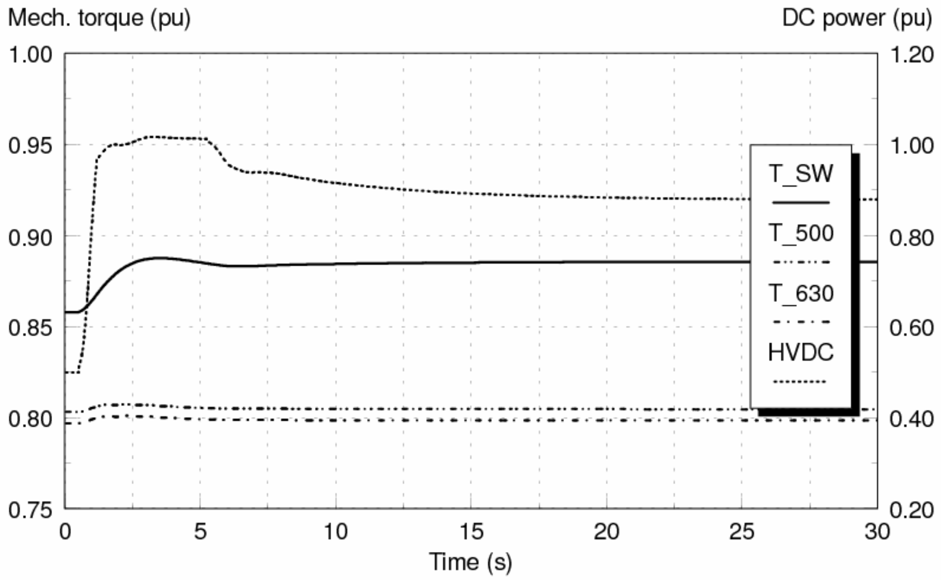

Figure C-8 HVDC connection saturating due to Primary Control order after loss of 500 MW generating capacity in receiving (thermal) system [26]

C.4 SECONDARY CONTROL (AUTOMATIC OR MANUAL SET POINT CONTROL)

Unlike a generating unit where Primary Control signals go to the turbine droop controller while Secondary Control signals normally change the operating point of the unit, in an HVDC connection both primary and Secondary Control signals go to the current order controller. Thus, there is no principal difference between these two functions from the HVDC perspective expect the necessary response time.

One issue worth considering, though, is the duration of sustained reserve. In the case of Primary Control, the activated reserve is supposed to be replaced by secondary reserves within 10-15 minutes. This time is too short to cause considerable heating of the cable before it returns to scheduled loading, and should not cause thermal cycling problems. In the case of secondary reserves, on the other hand, the duration of the activation is long enough to cause extra heating of the cable followed by cooling when the reserve is called off. This causes thermal, mechanical and chemical stress in the cable that might affect its lifetime.

Figure C-9 shows the relation between support to the thermal system (dPth) from the HVDC connection, the available capacity on the connection (dP) and the controller gain of the Primary Controller of the connection. Due to the overload capacity, the connection supports the receiving system with more than the available rated capacity.

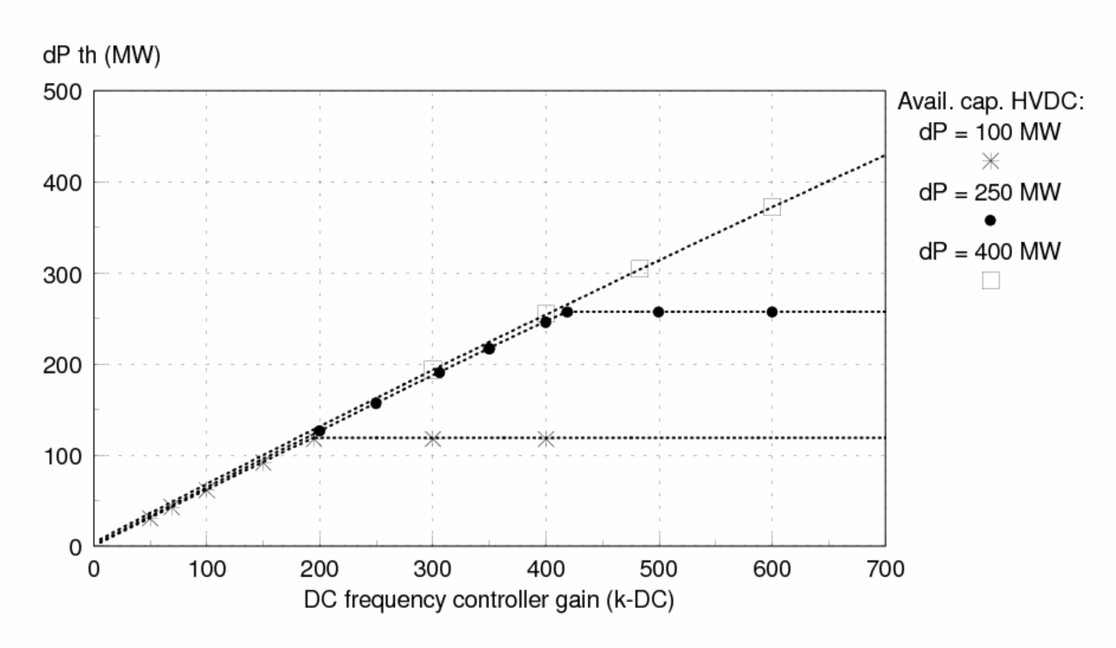

Figure C-9 MW support from HVDC connection to receiving (thermal) system as function of available capacity and controller gain [26]

SINTEF Energiforskning AS
Adresse: 7465 Trondheim
Telefon: 73 59 72 00

SINTEF Energy Research
Address: NO 7465 Trondheim
Phone: + 47 73 59 72 00